

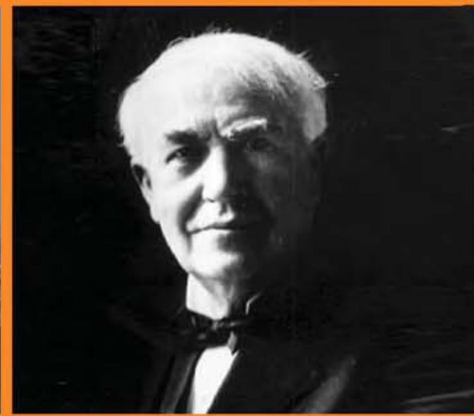

BOARD *and* CHIEF EXECUTIVES MEETING

September 10-12, 2013

The Broadmoor, Colorado Springs, CO

Edison Electric Institute

Power by Association℠

EEI

SCHEDULE OF EVENTS

September 10-12, 2013 The Broadmoor ■ Colorado Springs, Colorado

Wireless Access Code: User ID – EEI13 / PW - 123

MONDAY, SEPTEMBER 9, 2013

6:00 p.m.	Executive Committee Reception/Dinner	Donald Ross Room *(Golf Building)*

TUESDAY, SEPTEMBER 10, 2013

8:00 a.m. – 6:00 p.m.	EEI Registration	McGrew Room
8:30 a.m. – 1:30 p.m.	Executive Committee Meeting *(Buffet breakfast available at 7:30 a.m.)*	West Ballroom A/B
1:30 p.m. – 3:00 p.m.	PJM CEO Meeting	West Ballroom C/D
3:00 p.m. – 4:00 p.m.	Western CEO Meeting	Rocky Mountain C
6:00 p.m. – 9:00 p.m.	Welcome Reception and Dinner	Cheyenne Lodge

WEDNESDAY, SEPTEMBER 11, 2013

7:00 a.m. – 5:00 p.m.	EEI Registration	Rocky Mountain Foyer
7:30 a.m. – 8:30 a.m.	Conference Breakfast	Rocky Mountain C/D
7:30 a.m. – 8:30 a.m.	Executive Committee Breakfast w/Dr. Moniz	West Ballroom A/B
8:30 a.m. – 9:30 a.m.	The Honorable Ernest Moniz, U.S. Secretary of Energy Department of Energy	Rocky Mountain A/B
9:30 a.m. – 12:00 p.m.	**Board of Directors Strategic Discussion** Distributed Generation Panel Jim Hughes, CEO, First Solar Corp. Lewis Mills, Public Counsel, State of Missouri Mark Schiavoni, EVP, Operations, APS David Sparby, Sr. VP & Group President, Xcel Energy, Inc. David Wright, Immediate Past President, NARUC Distributed Generation Discussion Electrification Campaign DoD Base Issues Tax Reform Dodd-Frank Implementation	Rocky Mountain A/B
	Spouse/Guest Program Activities	
8:30 a.m. – 9:30 a.m.	Fitness Walk	Sun Lounge
11:00 a.m. – 11:45 a.m.	Voucher Distribution Guest Program	Crystal Room

12:00 p.m. – 2:00 p.m.	**Conference Luncheon** Mark Zandi, Chief Economist Moody's Analytics	Rocky Mountain C/D

2:00 p.m. – 4:30 p.m.	**Board of Directors Strategic Discussion**
	National Response Event
	Cyber Security
	FERC Issues
	    ROE
	    PURPA
	Substation Security (Executive Session, CEOs only)
		Rocky Mountain A/B

5:30 p.m. – 7:00 p.m.	Conference Reception	Lake Terrace Dining Room

<u>THURSDAY, SEPTEMBER 12, 2013</u>

7:00 a.m. – 1:00 p.m.	EEI Registration	Rocky Mountain Foyer
7:00 a.m. – 8:00 a.m.	IEE Management Committee	West Ballroom A/B
7:00 a.m. – 8:00 a.m.	Conference Breakfast	Rocky Mountain C/D
8:00 a.m. – 9:00 a.m.	The Honorable Philip D. Moeller Commissioner, FERC	Rocky Mountain A/B

9:00 a.m. – 11:30 a.m.	**Board of Directors Strategic Discussion**
	Environment
	    316b
	    Effluent Guidelines
	    Coal Ash
	    Regional Haze
	    Greenhouse Gas NSPS
	Natural Gas Issues
	Board of Directors Business Session
		Rocky Mountain A/B

11:30 a.m.	Conference Luncheon	Mountain View Terrace

GUIDELINES FOR ANTITRUST COMPLIANCE

The Edison Electric Institute and its member companies are committed to full compliance with all laws and regulations while maintaining the highest ethical standards in the conduct of our operations and activities. This commitment includes strict compliance with all federal and state antitrust laws.

Responsibility for Antitrust Compliance
Compliance with the antitrust laws is critical and is accomplished through education and close coordination with your counsel. Antitrust cases are complex and costly to defend. Antitrust violations may result in heavy fines and treble damages against corporations, and in fines, treble damages and imprisonment for individuals. You bear the ultimate responsibility for assuring that your actions and the actions of any of those under your direction comply with the antitrust laws. EEI's General Counsel's office will do its best to provide guidance on antitrust matters.

Antitrust Guidelines
In all EEI operations and activities, you must avoid any discussions or conduct that might violate the antitrust laws or even raise the appearance of impropriety. Intent to violate the antitrust laws is not a prerequisite to prosecution. You can be found liable for unintentional, inadvertent and accidental acts, comments or conduct.

- ***Do consult*** with counsel on any antitrust matters, especially regarding documents that touch on sensitive antitrust subjects such as pricing, bids, allocation of customers or territories, boycotts, tying arrangements and the like.

- ***Do consult*** with counsel on matters which raise antitrust concerns such as participating in new projects or programs, or submitting data for such activities.

- ***Do use*** a written agenda and take accurate minutes at every meeting and conference call. Have counsel review the agenda and minutes before they are put into final form and circulated.

- ***Do provide*** a copy of these guidelines to all participants at meetings.

- ***Do not discuss*** with other member companies at any time, including public and private meetings and social events:
  - your company's prices for products or services, or process charged by your competitors;
  - costs, discounts, terms of sale, profit margins or anything else that might affect prices;
  - the resale prices your customers should charge for products you sell them;
  - allocating markets, customers, territories or products with your competitors;
  - limiting production;
  - whether or not to deal with any other company; and
  - any competitively sensitive information concerning your own company or a competitor's company.

- ***Do not stay*** at a meeting or any other gathering or on a conference call if such discussions are taking place. Make sure your departure is noted for the record.

- ***Do not discuss*** with other member companies at any time, including public and private meetings and social events.

- ***Do not engage*** in any communication or create any documents or records that might be misinterpreted to suggest that EEI or your company condones or is involved in anticompetitive behavior.

- ***Do not make*** any comments you do not want to see in print.

Please contact EEI's General Counsel's Office whenever you have a question regarding EEI activities and antitrust issues.

J. Bruce Brown (202.508.5621)
Deputy General Counsel,
Corporate Affairs

Edward H. Comer (202.508.5615)
Vice President, General Counsel
& Corporate Secretary

030712

As Approved June 21, 2005

EDISON ELECTRIC INSTITUTE
DIRECTOR CONFLICT OF INTEREST POLICY

The Edison Electric Institute has been formed to advance the public service of producing, transmitting and distributing electricity and to aid our members to generate and sell electric energy, providing reliable and adequate service with due regard for the interests of our members' customers, investors, employees and the public.

EEI is committed to conducting business with the highest ethical standards in accordance with all applicable laws. This commitment applies to EEI's Directors, Officers, employees and the member company staffers who represent EEI or participate on EEI Committees and related activities. EEI's Officers and employees must conduct their activities in accordance with EEI's Core Values, Operating Principles, and Code of Conduct.

As leaders of EEI and representatives of EEI members, EEI Directors must exercise their fiduciary duties to take actions that are in the best interests of EEI and its membership as a whole, apply reasonable skill and judgment in managing EEI's affairs, exercise reasonable business judgment and pay attention to the activities and finances of EEI so that EEI's resources are used effectively and for legitimate business purposes.

When acting in their capacities as EEI Directors managing EEI's business affairs and finances, EEI Directors must put their personal and company interests aside and disclose any personal or company interest that may conflict with EEI's business interests.

Any person who believes that a Director or member is not fulfilling the intent of this statement should address their concerns to the Chair of the EEI Board of Directors or the President of EEI.

PJM CEO MEETING

EEI Fall Board and Chief Executives Meeting, September 2013

Bill Spence, Chairman, President and CEO, PPL Corp., will lead this biannual meeting with Terry Boston, President and CEO, PJM.

The meeting will provide an opportunity for update and discussion of some of the most pressing issues facing the PJM region: (i) Summer 2013 operating results; (ii) market issues including the reliability pricing model, demand response operability, and natural gas/electric coordination; (iii) MISO seams issues and coordination; and (iv) transmission planning, including Order No. 1000 regional and interregional compliance efforts.

EEI urges all CEOs and executive leaders with interest in the PJM region to join this meeting.

2013 Fall Board and Chief Executives Meeting

EEI

PJM CEO MEETING

Tuesday, September 10, 2013 ■ 1:30 p.m. – 3:00 p.m.

The Broadmoor ■ Colorado Springs, Colorado

Regular Meeting: 1:30 – 3:00 PM

I. Welcome and Introductions

Bill Spence, Chairman, President and CEO, PPL Corp.

II. PJM Update

Terry Boston, President and CEO, PJM

A. Summer 2013 Operating Results

- Weather Impact
- Scarcity Pricing

B. PJM Market Issues

- Reliability Pricing Model
  - May Auction; Long-term Outlook
  - Price Volatility
- Demand Response Operability
- Gas/Electric Coordination

C. MISO Coordination

- Resource Adequacy/Market Issues
- Firm Transmission for Capacity Transfers
- Transmission Planning

D. Transmission Planning

- Order No. 1000 Compliance Update
- Public Policy Issue: State Support for Atlantic Wind Project

E. Other Issues

III. Action Items/Next Steps

WESTERN CEO MEETING

With discussions still under way on a variety of issues related to WECC in the aftermath of the September 2011 blackout, we will have an opportunity to meet with Gary Stephenson, the CEO leading the new reliability entity in the West. Naturally we will entertain any other issues that you may want to surface during this session as well.

http://www.eei.org/issuesandpolicy/electricreliability/MemberDocuments/EL13-52EEIRequestforRehearing.pdf

July 8, 2013

Gary Stephenson Appointed as CEO Designate of Reliability Coordination Company

The Western Electricity Coordinating Council (WECC) announced today that Gary Stephenson has been appointed as CEO Designate of the planned spinoff entity currently referred to as the Reliability Coordination Company (RCCo). The appointment is effective on July 15, 2013. When bifurcation is complete and all necessary regulatory approvals have been achieved it is anticipated that Gary will become President and Chief Executive Officer of the RCCo.

Gary's experience with power plant development, wholesale and retail marketing, and industry restructuring in the WECC region spans almost twenty years. Most recently leading his own energy consultancy group (GBA Energy Partners), Gary was previously Executive Vice President, Operations, DPL Inc., where he was responsible for all operations at this integrated electric utility including power supply, transmission and distribution, customer service, competitive retail marketing, and commodity trading.

Prior to DPL, he was Vice President, Commercial Operations, InterGen (owner of the La Rosita plant near Mexicali, Mexico) from 2002 to 2004 and Vice President, Portfolio Management, PG&E National Energy Group (successor to PG&E Energy Trading) from 2000 to 2002. Gary held positions of increasing responsibility at PG&E Energy Trading and its predecessor companies between 1994 and 2000. While at PG&E National Energy Group, he was responsible for the commercialization of many significant power projects including La Paloma and Mountainview in California and Harquahala in Arizona. Additionally, Gary managed marketing for the Pacific Gas Transmission interstate gas pipeline.

Gary has an M.B.A. from the Tuck School of Business at Dartmouth College, an M.S. in Electrical Engineering from Polytechnic University and a B.S. in Electrical Engineering from Lafayette College. He is a Director of the Air Force Museum Foundation and an adjunct professor in the School of Engineering at the University of Dayton.

August 19, 2013

I am pleased to announce that a name, tagline, and logo for, what is currently referred to as, the Reliability Coordination Company (RCCo) have been approved by the RCCo Interim Board Committee.

The New Name

From the date of bifurcation, January 1, 2014, the company will be known as **Peak Reliability**.

"Reliability" reinforces the key elements of the function that the RC performs and ties back to our mission statement:

> *The RCCo shall support and promote the social welfare by endeavoring to ensure* **reliability** *by providing real-time, Interconnection-wide oversight of the Bulk Electric System (BES) within the RCCo footprint, coordinating necessary real-time and seasonal planning and modeling, and ensuring that data critical to the reliable and efficient operation of the BES is shared appropriately.*

"Peak" suggests excellence, the pinnacle, the highest point. In addition, it aligns with the NERC definition of the RC function[1], part of which is, "…the highest level of authority who is responsible for the reliable operation of the Bulk Electric System…."

Combined into **Peak Reliability**, the name is short and easy to remember, is not in use by any other organization, is not geographically restrictive, nor does it suggest an Independent System Operator (ISO) or Regional Transmission Organization (RTO).

A New Tagline

Peak Reliability will appear in many formats with the tagline "Assuring the wide area view." The tagline reinforces the RC's unique ability to see the whole of the Western Interconnection. In addition, it reflects the *"….real-time, Interconnection-wide oversight of the BES…:* referenced in the mission statement and the portion of the NERC definition for the RC function that says, "…has the Wide Area view of the Bulk Electric System…."

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[1] http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

A New Logo

You may recognize the derivation of the new logo which has roots in a balanced three-phase voltage phasor diagram. The colors represent standard North American three-phase colors (blue, red, and black).

Logo + Name + Tagline

PEAKRELIABILITY
assuring the wide area view

Next Steps

New stationery, signage, and templates are in development. Domain names have been registered for the new company and we anticipate migrating to the new domain name and URL (www.peakrc.com) in time for bifurcation.

DR. ERNEST MONIZ

As United States Secretary of Energy, Dr. Ernest Moniz is tasked with implementing critical Department of Energy missions in support of President Obama's goals of growing the economy, enhancing security and protecting the environment. This encompasses advancing the President's all-of-the-above energy strategy, maintaining the nuclear deterrent and reducing the nuclear danger, promoting American leadership in science and clean energy technology innovation, cleaning up the legacy of the cold war, and strengthening management and performance.

Prior to his appointment, Dr. Moniz was the Cecil and Ida Green Professor of Physics and Engineering Systems at the Massachusetts Institute of Technology (MIT), where he was a faculty member since 1973. At MIT, he headed the Department of Physics and the Bates Linear Accelerator Center. Most recently, Dr. Moniz served as the founding Director of the MIT Energy Initiative and of the MIT Laboratory for Energy and the Environment and was a leader of multidisciplinary technology and policy studies on the future of nuclear power, coal, nuclear fuel cycles, natural gas, and solar energy in a low-carbon world.

From 1997 until January 2001, Dr. Moniz served as Under Secretary of the Department of Energy. He was responsible for overseeing the Department's science and energy programs, leading a comprehensive review of nuclear weapons stockpile stewardship, and serving as the Secretary's special negotiator for the disposition of Russian nuclear materials. From 1995 to 1997, he served as Associate Director for Science in the Office of Science and Technology Policy in the Executive Office of the President.

In addition to his work at MIT, the White House, and the Department of Energy, Dr. Moniz has served on a number of boards of directors and commissions involving science, energy and security. These include President Obama's Council of Advisors on Science and Technology, the Department of Defense Threat Reduction Advisory Committee, and the Blue Ribbon Commission on America's Nuclear Future.

Dr. Moniz received a Bachelor of Science degree *summa cum laude* in Physics from Boston College, a Doctorate in Theoretical Physics from Stanford University, and honorary degrees from the University of Athens, the University of Erlangen-Nurenberg, and Michigan State University.

DISTRIBUTED GENERATION

Distributed Generation Panel

Michael Yackira will lead a panel discussion of the critical industry issues surrounding the impact of net metering and related distributed generation policies. The discussion includes perspectives from regulators, state legislators, consumer advocates and the renewable community. The session will conclude with a closed door, "around-the-room" discussion of member company insights on policies, strategies and tactics.

EEI provides a variety of information for your review. A series of maps identify the full scope of penetration across the states of renewable portfolio, net metering and related policies. There is also a critique of major studies conducted by DG advocates on why the "value of solar power" justifies the continued use of net metering. We also summarize information about the relative costs of rooftop and central station solar. These materials will be useful background for our general discussion of the broad range of DG issues, including reports from CEOs in states where net metering is currently being contested.

"A Policy Framework for Designing Distributed Generation Tariffs" was prepared by members of the EEI Rate Committee for use with state regulators and their staff. It provides numerical examples to illustrate why net metering that values distributed generation at the retail price for power fails to allow a utility to recover costs for distribution, transmission and other services that a distributed generator uses.

Other attachments identify individuals and groups that oppose continuation of net metering as DG expands and explain the reasons for their support. This includes a link to the full Report of the Critical Consumer Issues Forum and a description of the upcoming effort to build on the consensus framework and principles that were developed earlier this year by consumer advocates, regulators and utilities.

The IEE Report on the "Value of the Grid" addresses why rooftop solar and similar distributed generation technologies continue to rely upon the grid for a large number of support and back-up services and thus should continue to pay for such services.

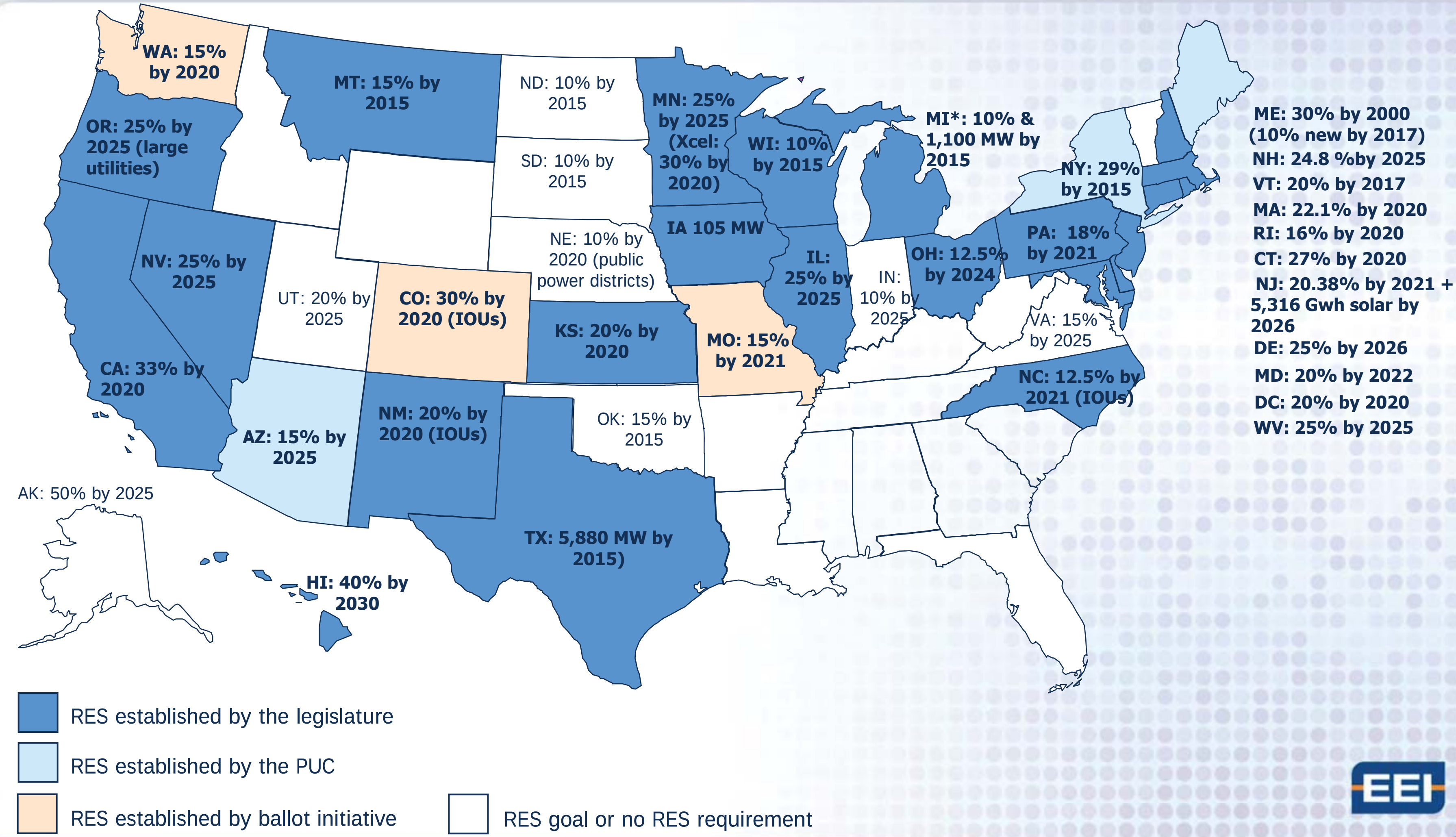
Please also look at the PURPA related documents. There is a short explanation of developments at FERC reinterpreting the concept of avoided costs under PURPA whenever the next source of generation is required to be a renewable facility under a state renewable portfolio or similar law. FERC's approach is likely to directly impact the pricing of DG whenever a utility has not achieved RPS requirements – so that the "next" avoided generation is one that satisfies those renewable requirements.

EEI Board Lead:

Michael W. Yackira, President & CEO, NV Energy, Inc., and EEI Chairman

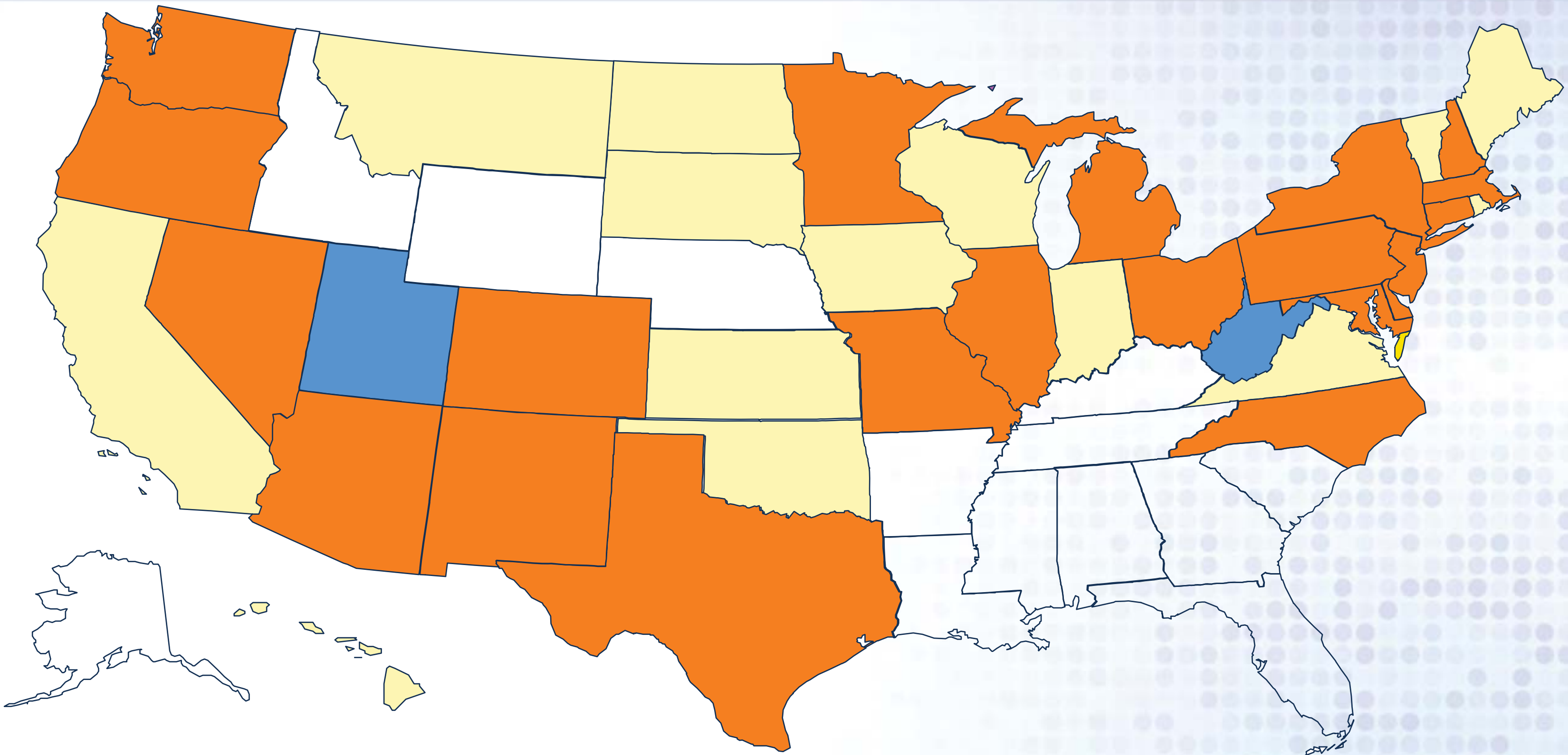
Additional Resource:
CCIF Report
http://www.eei.org/about/meetings/Meeting_Documents/CCIFforDG.pdf

State RES Policies



Source: www.dsireusa.org, March 2013; Federal Energy Regulatory Commission; EEI

RES Policies With Solar/DG Provisions



Renewable electricity standard with solar / distributed generation (DG) provision

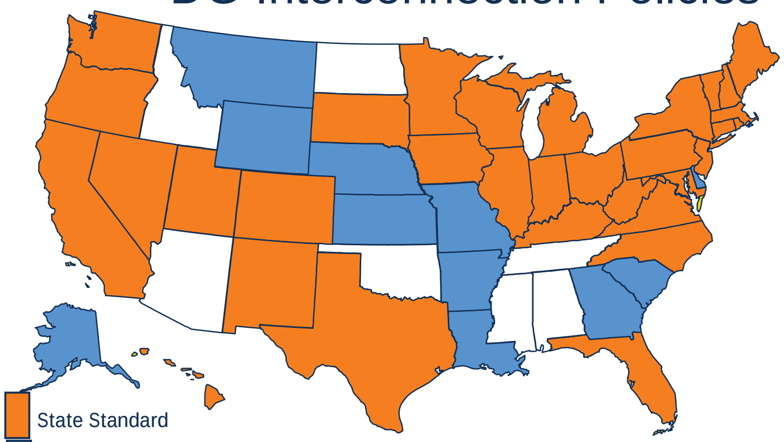
Renewable electricity goal with solar / DG provision

Renewable electricity standard or goal with no solar / DG provision

Source: www.dsireusa.org, March 2013, EEI

State Policies

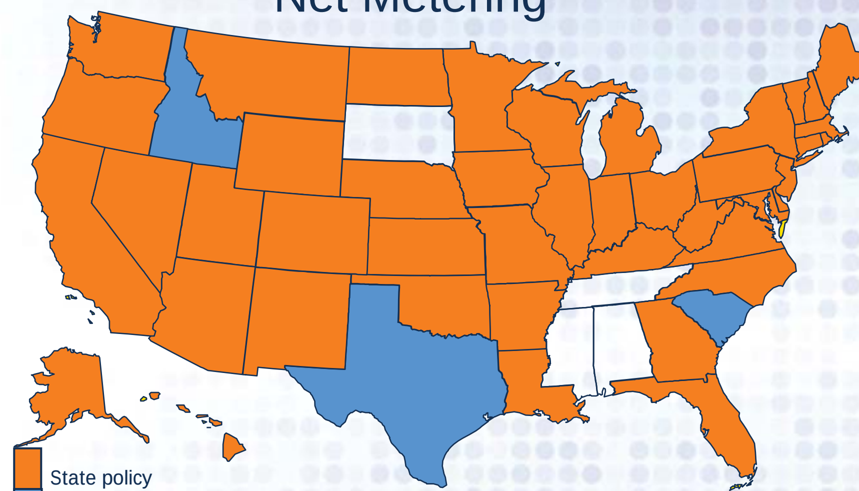
DG Interconnection Policies



State Standard

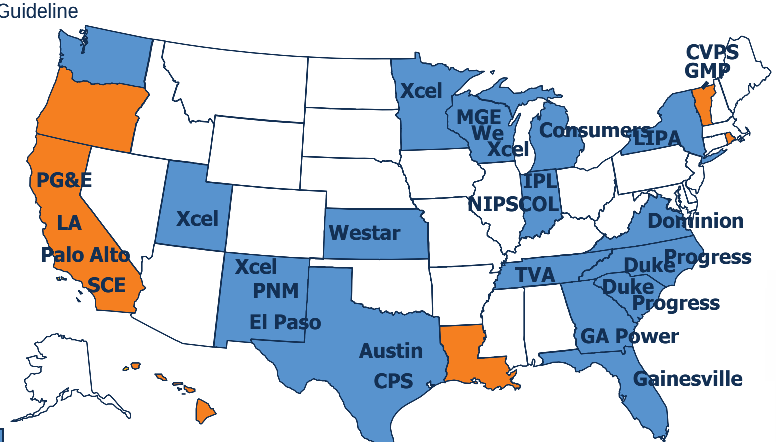
State Guideline

Net Metering



State policy

Voluntary utility program(s) only



Utility Feed-In Tariff, solar buy-back and other performance-based incentives

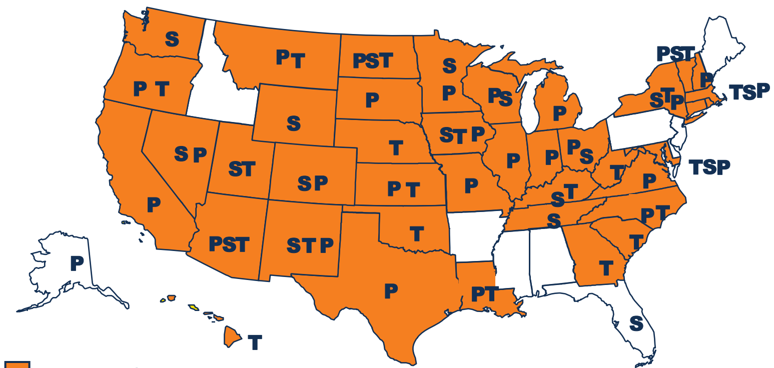
State mandated Feed-In Tariff or pilot program

Feed-In Tariffs and Performance Based Incentives

Source: www.dsireusa.org, EEI

State and Utility Financial Incentives

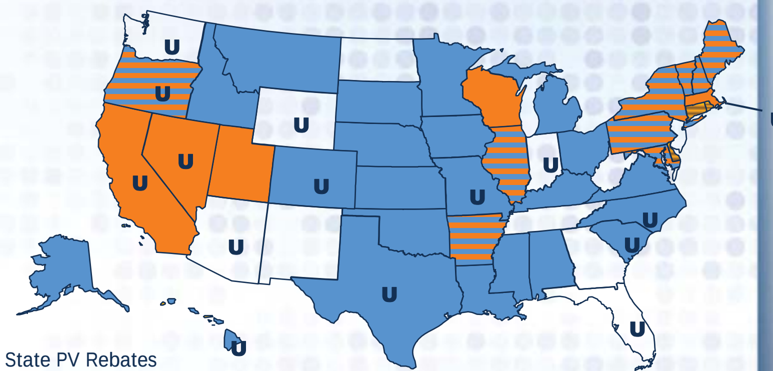
State Tax Incentives



Tax Incentives

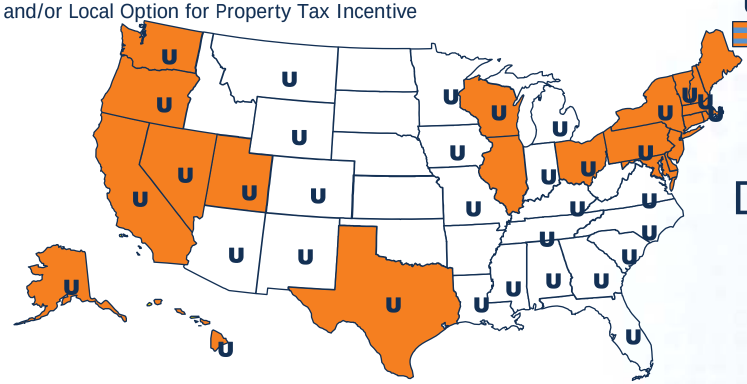
T State Tax Credit for Residential and/or Commercial Projects
S State Sales Tax Incentives
P State Property Tax Incentives and/or Local Option for Property Tax Incentive

State Rebates and Loans



State PV Rebates
Loan Programs
U Utility Incentive(s)
State PV Rebates and Loan Programs

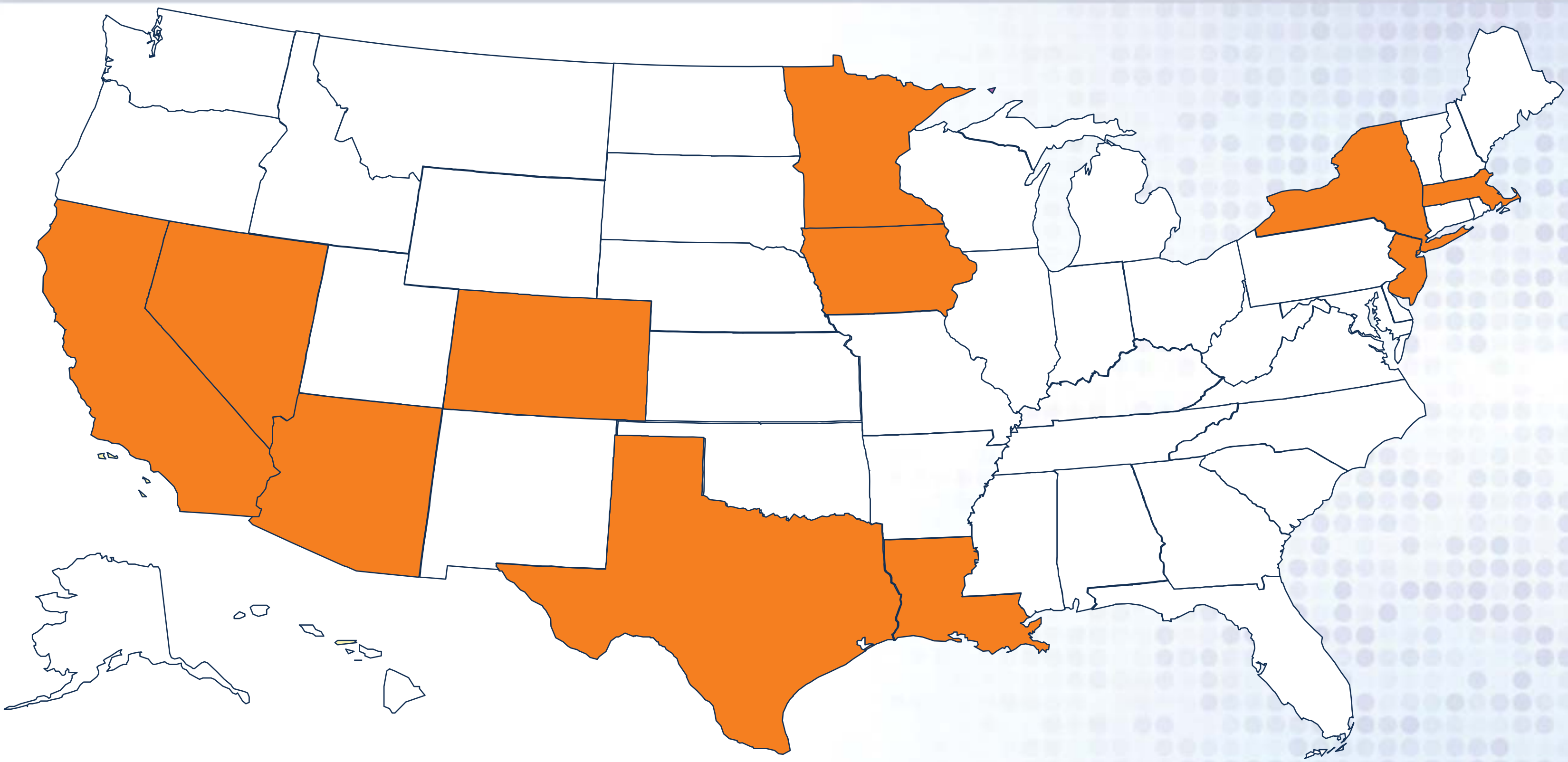
Direct Cash Incentives



State Direct Cash Incentives for PV
U Utility Direct Cash Incentive(s) for PV and/or Solar Water Heating

Source: www.dsireusa.org , EEI

Net Metering/Value of Solar Hot Spots



SEIA Identified “Net Metering/Value of Solar Hot Spots”

Utility-Scale Solar PV Is More Economical Than Distributed Solar PV

In recent months, numerous media and marketing communications from businesses have helped spread the idea that distributed solar, i.e., rooftop solar, is the best solar option for states to pursue. These comments have often been accompanied by the mistaken assumption that rooftop solar is more affordable than other generation technologies.

It is important to dispel this notion and provide factual support to electric companies and policymakers willing to promote all forms and sizes of solar power, distributed as well as utility-scale. In addition to existing cost comparisons and analyses, there are two ongoing industry efforts that will look at the solar cost issue in different, yet complementary, ways. One will be conducted by the National Regulatory Research Institute (NRRI) and the other by the solar manufacturer and developer First Solar.

Existing cost analyses

There are several sources for information comparing the costs of utility-scale and distributed-scale solar photovoltaics (PV) in the U.S., including the Lawrence Berkeley National Laboratory (LBNL), the National Renewable Energy Laboratory (NREL), GTM Research, and Lazard.

NREL summarizes the state of solar costs as follows: [1]

- The cost of solar energy varies by region, site characteristics, technology, and size of installation. Solar resource availability, labor rates, and permitting costs all impact the installation cost.
- Utility-scale solar PV is more economical than distributed solar PV. In general, utility-scale solar PV costs about one-third less than DG solar PV, and with current subsidies and tax breaks, is cost competitive with wind and conventional peaking resources in many locations.
- The primary factors that enable utility-scale solar PV to cost less than DG solar PV are:
    - Standardized construction and installation approaches.
    - Lower installer profit margins and overhead costs.
    - Economies of scale through the supply chain (panels as well as other components) that lead to reduced capital costs.

[1] "Residential, Commercial, and Utility-Scale Photovoltaic (PV) System Prices in the United States: Current Drivers and Cost-Reduction Opportunities", Alan Goodrich, Ted James, and Michael Woodhouse, February 2012. http://www.nrel.gov/docs/fy12osti/53347.pdf

- Utility-scale solar PV development realizes greater efficiency throughout the supply chain and installation process with reduced overhead and profit for installers.
  - DG solar installers take up to 30% profit on the mark-up of the retail price of materials as well as in labor rates, versus a 10% mark-up for utility-scale installations. This is partially due to a lack of experience that leads DG installers to build a bigger cushion into the total installation costs to account for unexpected setbacks during installation.
  - 5% of the total DG solar installation cost is installer profit vs. 1% for utility-scale solar.
  - 6% of the total DG solar installation cost is installer overhead vs. 2% for utility-scale solar.

Installed Costs

- According to LBNL, the median installed price of solar PV in 2012 was:
  - Residential rooftop systems (< 10kW) $5.30/watt
  - Commercial systems (> 10 kW and < 100 kW) $4.90/watt
  - Commercial systems (> 100 kW) $4.60/watt
  - Utility-scale systems (> 2 MW) $3.20-$3.60/watt

http://emp.lbl.gov/publications/tracking-sun-vi-historical-summary-installed-price-photovoltaics-united-states-1998-201

- According to GTM Research, the installed price of utility-scale solar PV is approximately half that of residential solar PV. In the first quarter of 2013, the average installed cost of solar PV was:
  - Residential rooftop systems $4.93/watt ($3-$8/watt range)
  - Commercial systems $3.92/watt ($2.50-$8/watt range)
  - Utility-scale systems $2.14/watt ($2-$4/watt range)

http://www.seia.org/research-resources/us-solar-market-insight

Levelized Cost of Energy

- According to Lazard, rooftop solar PV is one of the most expensive ways to generate electricity. The unsubsidized levelized cost of energy for solar PV in the U.S. is:
  - Rooftop solar $149-$204/MWh
  - Utility-scale solar $101-$149/MWh

Projected new analyses

NRRI is interested in conducting a study that would look into the costs of solar PV. A formal proposal is still being developed, and no final details are available. Given their regulatory focus, however, this study will likely concentrate on: 1) a discussion of the costs and cost structure of the different technology segments; 2) an examination of the different factors that affect cost comparisons or that skew a fair assessment, specifically incentives, rate structures, rate treatment of costs; and 3) an assessment of unintended regulatory consequences (i.e., cost-shifting) and, possibly, an analysis of best practices and/or different options based on state case studies. NRRI would like to be able to present this report to regulators at the fall NARUC meeting.

First Solar is considering a project that will explore the relative advantages and impacts of the three types of solar PV (distributed, community and utility-scale) on the costs of owning and operating the distribution system. This effort would go beyond a superficial examination of the costs and benefits of solar power, like many “value of solar” calculations do, and would try to determine the different impacts on the utilities’ cost of service of equal amounts of distributed, community and utility-scale solar power.

Solar Distributed Generation: A Critical Review of the Solar Industry's Benefits and Costs Methodology

Distributed solar energy is an important utility resource. Determining the value of the resource to the utility is a function of its impact on the utility's distribution, transmission and generation (energy and capacity) systems. Unfortunately, recent solar industry studies overstate the benefits, understate the costs and misuse the well-established Standard Practice Manual (SPM) for utility demand-side resource cost-effectiveness.

The following errors occur in recent studies prepared by the solar industry.

Peak solar energy production does not coincide with utility system peak loads. A mismatch exists between the outputs of rooftop solar and the utility's system peak. Studies that assume equivalent capacity value of solar at the utilities system peak overstates the benefits of new solar distributed generation (DG).

Standby generation and integration costs are largely ignored. Standby generation and integration costs for uncertain and variable DG are significant, and increase in proportion to the rate of installation of these resources. These costs depend on customer demand characteristics, the concentration of DG in specific locations and growth over time. Studies that assume a fixed integration cost over a 20 year period ignore increases in the following costs: ancillary services, reserves (including ramping), voltage rise effect, power quality, evaluation and planning, programming, overhead, administration and investments in upgraded distribution assets.

Assuming that all energy offset by solar DG would come from a simple cycle gas combustion turbine significantly overstates the benefits. A significant portion of displaced energy will likely come from highly efficient combined-cycle resources. Current and forecasted system heat rates must be derived from detailed production cost modeling.

Solar DG value is based on actual costs and benefits, not theoretical costs and benefits. Costs and benefits to the utility must be based on specific costs avoided on the actual operation of the existing utility system. Studies that claim that the value of rooftop solar is more than double the cost to operate an existing electric system on a per unit basis indicate that the study claims benefits that are not based on actual operations. For example, the incremental generating capacity benefit of rooftop solar DG is zero if a utility system does not need additional generating capacity in a given year.

There is no benefit from avoiding the cost to comply with a Renewable Portfolio Standard when the RPS has already been met. Including theoretical values for over complying with RPS based on dubious assumptions that solar DG is a more economical way of achieving compliance, overstates the benefits of solar DG.

Outdated assumptions result in an overestimation of the benefit of rooftop solar DG. Studies must use the best available assumptions for customer growth, fuel prices, and carbon prices.

Including environmental cost benefits for currently regulated air emissions assigns benefits that will not actually appear.
Since regulated criteria air pollutants (SO_2, NO_x, and PM 10) are limited by current law, studies that claim monetized reductions for these pollutants inappropriately claim externality benefits that do not occur.

Using the Rate Impact Measure (RIM) test to determine cost effectiveness indicates that the results are not economically efficient. The RIM test is not a test for cost effectiveness. Rather, it is used solely to determine the impact in rates of a specific demand-side management (DSM) program(s). It then provides the rate impact on all customers from the program(s) implementation. If the faulty assumptions described above are corrected, the RIM test would likely be negative and therefore projected solar DG penetration would increase rates to all customers. This would indicate that non-DG customers would pay for the benefits gained by solar DG customers.

Edison Electric Institute

A Policy Framework for Designing Distributed Generation Tariffs

Prepared by:
Edison Electric Institute

August 2013

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EXECUTIVE SUMMARY

It is a fundamental rule of electric utility regulation that customers should pay for the costs of the services they receive from their utility and the electric power grid and not pay for the costs of services provided to other customers. This principle applies to the services electric utilities provide to all customers, including customers with distributed generation (DG) systems. DG systems are small-scale, on-site power sources located at or near customers' homes or businesses. Some common examples include solar panels, energy storage devices, fuel cells, microturbines, small wind, and combined heat and power systems.

Current methods of net metering for customers with DG systems generally fail this simple principle. When customers with DG systems use the grid to sell any excess electricity that they generate to electric utilities and are credited at the full retail price for this electricity (i.e., retail price net metering), they avoid paying many of the fixed infrastructure costs associated with the services they require and receive from the utility and the grid. This occurs because many rate schedules provide for the recovery of fixed charges for delivery and related activities through a variable cost part of the retail rate for power. In these situations, retail price net metering effectively forces other customers without DG systems to pay those costs.

State rate policies for DG should be updated to ensure that everyone who uses the electric grid helps pay to maintain it and to keep it operating reliably at all times. Any cost-shifting to non-DG participating customers created by current net metering rate design policy should be eliminated. Otherwise, these net metering policies will result in increasing numbers of customers avoiding payment of the costs of providing them service, with a decreasing number of customers assuming such costs. This is a long-term untenable process.

This paper is designed 1) to explain to utility regulatory commissions and staff how certain net metering policies enable utility customers with DG systems to avoid paying for the costs of critical delivery and support services that they use and 2) to provide alternative approaches that fairly compensate such providers for their generation services, while also ensuring that they continue to pay for the delivery and other services upon which they rely.

Section 1 more clearly defines the issue, explains cost causation and the cost-shifting problem, and provides three examples to illustrate the problems that may arise under retail net metering as customers install DG systems.

Section 2 identifies numerous alternative ratemaking approaches that would assure that DG customers pay their share of the costs of the grid and would treat both DG participants and non-participants in a fair manner. These include, for example, establishing a fixed charge for customers with DG systems to ensure utility recovery of the full cost of the use of the distribution system without cost shifting, and net metering with bidirectional meters as well as various buy/sell arrangements.

Section 3 explains why payments for surplus power from distributed generators should reflect the "avoided cost" from the utility's perspective. Section 3 also explains recent decisions by the Federal Energy Regulatory Commission (FERC) that allow avoided cost to be determined separately for renewable generation when states require the purchase of such renewable sources of power.

Some DG stakeholders advocate that the utility costs shifted to other customers represent compensation for the alleged benefits that customers with DG provide to other utility customers and/or society at large. The extent to which DG actually produces the claimed benefits is extensively debated. Benefits specific to the utility should be determined using a directly quantifiable approach that measures the net cost impact of DG to the utility. The value of "externalities" (benefits to society) is not and should not be directly accounted for in utility rates.

SECTION 1

Defining the Issue

The National Academy of Engineering called the North American power grid the "supreme engineering achievement of the 20th century." Grid electricity has placed its stamp on the world, changing the standard of living by introducing electricity to almost every facet of daily life. It has fundamentally changed the way all customers experience the world. It powers everything from homes, to businesses and industries, to the nation's critical infrastructure. Grid electricity provides value that far exceeds the actual cost of providing the service.[1] But unlike almost every other business, it has been a longstanding policy in the electric utility industry to charge customers based on the cost to provide a service. Utilities do not charge based on the value their customers receive.

While DG may be changing the way some utility customers interact with the utility grid, the same cost-based approach used for all utility rates should apply to customers who choose DG alternatives. As such, rate design should reflect the utility's cost-of-service and should be guided by the principle of cost causation. Retail utility tariffs should be designed such that all customers, whether they are customers with DG systems or not, pay their share of the costs the utility incurs to serve them.

Cost Causation and the Cost-Shifting Problem

It is a fundamental rule of utility regulation that customers should pay for the costs of the services they receive from a utility and not pay for the costs of services provided to other customers. Proper cost allocation is essential to fair ratemaking and the avoidance of hidden cross-subsidies. Deviations from this policy lead to distorted incentives and diseconomies that are not sustainable over time, as demonstrated by recent experiences in Europe.

Today, many state net metering policies are impacting electricity customers and the power grid upon which we all depend, leading policymakers to review the need for them now that rooftop solar and other DG systems have become more developed. Unlike customers who use the grid only to buy power, customers with rooftop solar or other DG systems use the grid both to buy and to sell electricity. Because of the way that some net metering policies originally were designed, net-metered customers are credited for the power they sell to electric companies usually at the full retail electricity rate, which includes all of the fixed costs of the poles, wires, meters, advanced technologies, and other infrastructure that make the electric grid safe, reliable, and able to accommodate solar panels and other DG systems. This paper refers to that practice as "retail price net metering."

Through the credit they receive, net-metered customers effectively are avoiding paying the costs for the grid, which they use to buy and to sell power and which supports the reliability of the power that they generate. As a result, these costs are shifted to those customers without rooftop solar or other DG systems through higher utility bills, unfairly impacting many working families.

[1] See "Lines Down" by Steve Mitnick (2013) for a more complete discussion of the value of grid electricity.

Three examples below illustrate the problems that may arise under retail net metering as customers install DG.[2] Example 1 represents a utility customer who does not self-generate and uses 1,000 kilowatt-hours (kWh) of electricity per month. Example 2 shows a utility customer with DG who generates 1,000 kWh/month and also uses 1,000 kWh/month. (While this customer may take energy from the utility at different times during the month, depending on the relationship between his load and generation output, under net metering the customer's meter would record zero at the end of the month.) Example 3 shows the utility-customer transaction under a simultaneous buy-sell agreement, in which a customer purchases 1,000 kWh/month from the utility and the utility purchases all of the customer's output (500 kWh in this example) from the customer generation. The common element in each example is that the customer purchases 1,000kWh/month from the utility.

In the first example, the costs to the utility and the amount billed to the customer are the same ($128.50).

In the second example, the costs to the utility are $93.50[3] (see second column), but the amount the DG customer pays for those costs are only $11.50 (see fourth column). The difference between the two ($82) represents costs the utility incurs to serve the DG customer that are not recovered under net metering when the customer's output is valued at the retail rate. Note, both customers still purchase 1,000 kWh of electricity, but the net-metered customer pays much less, despite the fact that he uses the grid more both to buy and to sell power. Also note that the customer credit is much higher than simply the value of the generation it is displacing.

This disparity occurs largely because many of the utility's fixed costs of transmission, distribution, and other charges are recovered through charges based on energy usage. As long as the DG customer produces enough electricity at some time during the month to offset all of the electricity used at other times during the month (i.e., net zero usage), the customer avoids paying for any of the fixed costs of being connected to and supported by the utility grid. The customer may even avoid paying for various social programs (e.g., low-income support). As a result, these costs are shifted to other, non-DG customers. This dramatic imbalance between costs incurred and revenues contributed is not in the public interest in terms of maintaining the long-term health and viability of the grid.

The third example illustrates how these disparities can be avoided. There, the DG customer pays his or her bill for 1,000 kWh, as would normally be the case, and simultaneously receives a payment for 500 kWh of production from the DG unit, which is calculated on the wholesale value of the power. Under this approach, the customer continues to pay for transmission, distribution, and public benefit programs just like every other customer of the utility and is paid for the power that he produces at the wholesale price.

This example illustrates how customers with DG can enjoy the benefits they associate with DG and be compensated for the power that they produce.

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[2] Not included is an example of a customer with a DG system who chooses to become completely self-sufficient, totally islanded from the grid. In this case, the customer is not connected to the grid and the utility has no obligation to serve and incurs no costs.
[3] Note that there may be additional costs to serve DG customers (e.g., interconnection costs) that are not included in this example.

Example 1
Utility/Customer Cost Comparison
Residential Service
1,000 kWh Monthly Usage

Service	Cost to utility/month to provide electricity service	Representative rate	Description
Generation Capacity	$40	$0.04/kWh*	Fixed costs/mortgage cost for having generation capacity available to serve customers.
Generation Fuel and Purchased Power	$35	$0.035/kWh	Fuel and purchased power to serve customer requirements.
Transmission	$5	$0.005/kWh*	Fixed costs/mortgage cost for having transmission capacity available to serve customers and support the grid, including generation reserves.
Distribution	$30	$0.03/kWh*	Fixed costs/mortgage cost for having local grid and customer-specific facilities available to serve customers.
Metering	$3.50	$3.50	Cost to meter customer consumption.
Billing/Customer Accounting	$7	$7	Costs associated with billing and customer information systems.
Meter Reading	$1	$1	Cost to read meters, including communication costs for Automated Metering Infrastructure.
System Benefits/Public Programs/EE/RPS**	$7	$0.007/kWh*	Cost of customer programs, such as low-income support, and regulator-mandated programs, such as energy efficiency programs and renewable energy programs.
Total	$128.50		

*Fixed costs that are typically collected through volumetric charges in residential customer rates.

**EE refers to energy efficiency. RPS refers to renewable portfolio standard.

Example 2
Utility/Customer Cost Comparison
Residential Service for DG Customer
1,000 kWh Monthly Usage – 1,000 kWh Generated From DG System

Service	Cost to utility/month to provide electricity service	Representative rate	Amount paid by customer/month for service	Service costs shifted to non-DG customers**
Generation Capacity	$40	$0.04/kWh*	$0	$40
Generation Fuel and Purchased Power	$0	$0.035/kWh	$0	
Transmission	$5	$0.005/kWh*	$0	$5
Distribution	$30	$0.03/kWh*	$0	$30
Metering	$3.50	$3.50	$3.50	$0
Billing/Customer Accounting	$7	$7	$7	$0
Meter Reading	$1	$1	$1	$0
System Benefits/Public Programs/EE/RPS	$7	$0.007/kWh*	$0	$7
Total	$93.50		$11.50	$82

*Fixed costs that are typically collected through volumetric charges in residential customer rates.

**DG customers avoid paying these costs so customers without DG systems will ultimately pay the costs.

Example 3
Utility/Customer Cost Comparison
Residential Service for DG Customer Under Simultaneous Buy-Sell Agreement
1,000 kWh Monthly Usage – 500 Generated From DG System

Service	Cost to utility/month to provide electricity service	Representative rate	Amount paid by customer/month for service	Service costs shifted to non-DG customers***
Generation Capacity	$40	$0.04/kWh*	$40	$0
Generation Fuel and Purchased Power	$35	$0.035/kWh	$35	$0
Transmission	$5	$0.005/kWh*	$5	$0
Distribution	$30	$0.03/kWh*	$30	$0
Metering	$3.50		$3.50	$0
Billing/Customer Accounting	$7.00		$7.00	$0
Meter Reading	$1		$1	$0
System Benefits/Public Programs/EE/RPS	$7	$0.007/kWh	$7	$0
Generation Credit		$0.035/kWh	($17.50)	
Total	$128.50		$111.00**	$0

*Fixed costs that are typically collected through volumetric charges in residential customer rates.

**Assumes an avoided cost credit of 3.5 cents/kWh, the short-run generation fuel and purchased power rate. Depending upon the utility, the credit could be higher or lower based on the avoided cost of the fuel source assumed. Generation credit to customer is $17.50.

***Customers with DG systems avoid paying these costs so customers without DG systems ultimately will pay the costs.

Charging customers with DG systems according to a retail price net metering arrangement violates cost causation principles that are the foundation of ratemaking. Such a plan credits the DG customer at the full retail rate of electricity when that customer sells electricity to the utility. This over-compensates the customer by crediting the customer for all the delivery and grid services provided by the electric utility, when the customer generation provided to the utility accounts for only a small part of those services—wholesale generation. As described below, not only does net metering shift a portion of the DG customer's allocated share of fixed costs of grid service to other customers, it also increase the variable energy costs the utility incurs to serve those other customers.[4]

Further, customers with DG are leaning on the utility system to reverse power flows and are imposing more expenses for the system than generally appear on a customer's bill. The determination of whether the customer with DG is generating more than he uses is generally made over a period of time, such as a month. However, when dissected further, it becomes clear that, on a minute-by-minute basis, the customer with DG is generating more than he uses for a much greater percentage of the time than might show up on a monthly total. (Much of this loss of detail in tracking generation flows is avoided if the customer with DG has a two-meter or two-way system and operates under a rate scheme that accounts for both sales and purchases, such as the buy-sell agreement described in Example 3.)

Example 2 highlights the resulting mismatch. Under retail price net metering, the utility would pay the customer with DG, on average, 12.05 cents/kWh for every kWh the customer generated in excess of the customer's use at any one time, when the utility could purchase that same amount of power from other sources within a typical price range of 3.0 cents/kWh to 6.5 cents/kWh. The other customers on the system pay the difference. However, this does not capture the full impact of the difference, because the samples above use average prices for the sake of simplicity. For many utilities, costs to serve and costs recovered from customers vary by time blocks. For example, solar is strongest during on-peak time blocks in which both the system price and the retail rate are above average.

Some analysts might argue that it is appropriate to pay DG solar customers these high amounts because solar offers benefits to the utility system. For example, solar helps trim peak demand and, as observed in the example, many of the utility costs are driven by peak demand. However, while solar generally produces electricity during periods with above-average demand, its efficacy decreases dramatically during peak periods. (Moreover, the warmer the climate, the later electricity usage peaks in general, thus moving the system peak further away from the early afternoon peak for solar.) As an illustration of this, utility planners would likely plan for about 2 kilowatts (kW) of contribution to system demand for 5 kW solar systems due to the intermittency of the resource and the lack of coincidence with utility system peak.

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[4] The examples assume the customer generates an amount of electricity equal to or less than the customer's monthly use. What if the customer was to generate more electricity than he or she used? Currently customers with DG are almost exclusively compensated according to a net metering paradigm that, in essence, runs the meter backward when the customer is generating more electricity than is being used and forward when the customer is using more electricity than is being generated. Consequently, if the DG customer was to generate more than he uses, the utility might pay the customer a credit or some other form of compensation. Terms and conditions for this overall net metering scheme vary from utility to utility, but this is the basic plan currently followed for compensating customers with DG that are net sellers.

The buy-sell arrangement illustrated in Example 3 shows one approach to solve the problems of retail price net metering. In this example, the customer is credited with the wholesale value of his generation, but continues to pay for the transmission, distribution, and other services he receives from the utility. Here, the utility continues to receive payments for generation because it continues to provide power to the customer. Moreover, the utility has an obligation, as directed by its state public utility commission (PUC), to provide those services should the customer's DG system not perform because of intermittency or fail for other reasons.[5]

Other Complications

The analysis above reveals how retail price net metering can fail to recover the costs of providing grid services to DG customers. However, providing service to customers with DG systems is even more complex and costly for utilities than assumed above.

Customers with DG require services beyond those of non-DG customers on the system. For example, customers with DG often require advanced metering capabilities and enhanced billing services. These services are more expensive than standard services. The utility will likely also need to offer interconnection services that allow DG customers to access the grid and market, including engineering and design studies to properly design interconnection for these customers. Because utility rates currently recover many of these fixed distribution costs in variable kWh charges, if retail price net metering is applied, utilities will not recover these additional costs from customers with DG systems, thus shifting these costs to other customers.

DG customers also have the potential to provide some benefits to the grid. It would be just as unfair—to the extent that those benefits have a direct effect on reducing the utility's revenue requirement—to shift those benefits to non-DG customers as it is unfair to shift those costs of DG that have the effect of increasing the utility's revenue requirement to non-DG customers. Costs and benefits that directly affect the utility's revenue requirement—or the total cost of providing grid electricity to all customers, both DG and non-DG—should be accounted for and fairly allocated as part of the regulatory process. These may include, for example, the avoided costs of upgrading transmission or distribution facilities.

DG advocates believe that crediting customers with DG the full retail rate compensates those customers for the additional benefits that DG conveys to the system. However, given that 43 states have some form of net metering and further given that not all DG is alike in terms of environmental benefits and other qualities, it is unlikely that the full retail rate in each of these 43 jurisdictions

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[5] The value of that capacity is dependent on a number of factors. If a utility has excess capacity, the value of the incremental capacity any individual customer with DG offsets is effectively zero. In aggregate there are some reductions in system requirements, and, in jurisdictions with capacity markets, there is a fairly transparent value, which is probably not zero. But the aggregate value is very circumstantial. Further, the utility's purchase of DG generation is no different than the utility's purchase of generation on the wholesale market. The contractual wholesale market price takes into account all of the costs incurred and saved by the utility in the transaction. These contractual wholesale transactions usually include performance clauses that specify conditions that customers with DG currently do not need to meet. Absent those performance clauses, the price of that generation would be heavily discounted.

matches the value that DG provides to the utility and its non-DG customers. Consequently, this "rough justice" perspective is often called into question.

Importantly, many of the benefits often associated with DG do not directly affect utility revenue requirements. The benefits most often mentioned are externalities that accrue to society more generally. Externality values are the most difficult to model and are currently not reflected directly in the utility pricing model. They should not be accounted for in utility rates.

SECTION 2

Alternative Rate Structures for Distributed Generation Customers

For decades electricity customers have had the ability to own and to operate generating facilities on their premises, including combined heat and power plants in factories, backup turbine generators in commercial buildings, and solar panels on the roofs of commercial facilities. Electric utilities always have had rate designs for purchasing power from these energy resources. In recent years, there has been growing interest in using small versions of these resources, which connect directly to the distribution network rather than the higher-voltage transmission grid, and more widespread adoption by residential and small general service customers. These facilities are known as distributed generation (DG), and the rates for service to these customers are primarily regulated by state commissions.

Traditionally, rates that had been designed for residential and commercial customers, when their use of these resources was relatively uncommon, were designed for simplicity, rather than in strict accord with principles of cost causation. If customers on these rates who installed DG were over-compensated for the electricity that they sold back to the local utility, the impact on other customers was negligible, because the amount of electricity purchased was insignificant.

With more widespread adoption of DG by more customers, the incorrect pricing of DG power has resulted in a tangible increase in electricity costs to other customers. To address this, many utilities have adopted new approaches to designing rates for DG. This section describes some of the new approaches that have been implemented, along with the particular issues or design questions that might guide a utility's or state commission's choice to adopt one approach rather than another.

General Rate Design Approaches for Purchases of Customer-Provided Electricity

Retail Price Net Metering

A common rate design used to compensate residential (and small general service customers) for power provided from onsite electricity generation facilities is retail price net metering, as discussed in Section 1. In its most common form, this type of rate enables customers to retain their regular meter. When power is being provided from onsite generation, the electric meter slows or—in cases where onsite electricity generation is exceeding what a customer is actually using—actually runs backwards. With customer usage being recorded by the traditional single, standard interval meter, the utility is incapable of knowing how much electricity the customer actually produced. Hence, a customer on this rate is simply billed for net electricity consumed. In those cases when net electricity usage is negative (because the customer produced more power during a billing period than was consumed), it is standard practice to carry this forward to future bills as an energy or financial credit, rather than to actually send a payment to the customer. Even in those billing periods where there is a net electricity surplus, the customer may still receive a fixed charge for service, which is generally equivalent to the fixed customer and/or demand charges that are part of the standard rate design.

Initially, the simplicity of the rate design, and the fact that no additional metering equipment was required to support it, made net metering attractive. The fundamental flaw in this approach stems from the fact that, by paying the customer for the full retail rate of electricity, the customer is invariably being paid for more than merely the electricity he generates and delivers to the utility. To the extent that a utility is recovering its fixed costs of service in the volumetric (i.e., per kilowatt-hour) portion of the retail rate, then the utility is actually paying, rather than charging, the customer with DG for its delivery and grid services whenever the customer is supplying electricity. Moreover, the advent of smart meters has made the process of tracking customer use and sales much simpler and more cost-effective.

Responses to Retail Price Net Metering

Many utilities, in addressing this issue, have elected to view this as more of a problem stemming from rate design, rather than net metering itself. If a utility can collect all or most of its fixed charges of service in a fixed customer charge and/or monthly demand charge, much of the cost misallocations stemming from retail price net metering disappear. With a rate design more closely aligned with cost causation, in cases where a customer generates a net surplus of electricity in any billing period, that customer still would be billed for the fixed costs of service and only would be compensated for the electricity "commodity." Therefore, many electric distribution companies have moved toward fixed/variable rate designs that include larger fixed monthly customer charges that are more proportional to fixed costs. In lieu of a general redesign of rates, if DG tariffs at least have a larger monthly charge, then cost recovery and subsidization problems stemming from net metering can be mitigated.

There is still a potential problem, however, when fixed costs are passed on to customers in the form of a demand charge, because demand charges are usually set based upon a customer's peak electricity usage and/or demand only during peak periods. If a customer has reduced peak demand (measured as peak net energy consumption) because of onsite generation facilities, then the computed demand charge may understate the system capacity that the customer is still actually using during other hours. On the other hand, customers with onsite generation might contend that this "phantom capacity" should not be provided at the conventional full retail rate, since it is now rarely used, if ever, and has really become only a standby service. This issue has been less predominant with residential net metering rates, since standard residential rate designs generally consist of a customer charge only to recover fixed costs of service and no demand charge. The issue is also less predominant with variable energy resources, such as solar or wind, since these resources tend to have a limited impact on reducing a customer's peak demand and consequent demand charges, although this could change when more efficient and affordable electricity storage systems begin to accompany onsite variable resources.

Net Metering with Separate Compensation for Electricity Exports

One approach to mitigating the cost mismatch inherent in net metering is to establish a fair value rate for net electricity provided to the utility and apply this rate to the purchase of that electricity. If a standard meter is being used, this could only be done in billing months where total electricity produced by the customer exceeded total electricity consumed, and the special rate would be applied to the excess. However, if a meter is required that is capable of separately measuring total energy exported, then this rate could be applied for all energy supplied to the utility by the customer during the billing period. In either case, the customer still would be billed under the standard applicable

retail rate for net energy consumed. While this approach provides the utility with the flexibility to set a price on the surplus electricity that it receives from the customer, it does not completely remedy the cost mismatch problem. When a customer's self-generation is merely reducing net consumption, then the amount being reduced still is being credited essentially at the full retail rate.

Net Metering with Bidirectional Meters

Another approach to rectifying the cost mismatch described above is to require the use of a meter capable of measuring both total energy consumption and total energy production. With the use of such meters, the most common approach to net metering is to bill the customer under the standard applicable retail rate for all energy consumed, and then to deduct from this bill a credit for energy supplied by the customer at a price that is established by the utility, and which is intended to represent the fair value of the electricity that is purchased. The advantage to this approach is that it ensures that the customer will pay all fixed costs of service, including demand charges, which will continue to be calculated based upon the customer's total energy consumption. This approach provides the utility with the flexibility to set a price on the electricity that it buys back from the customer. Another benefit to this approach is that it obviates the need to fundamentally redesign the standard retail rates in order to better align fixed costs of service with fixed customer charges.

Buy/Sell Tariffs

Another approach, which is a variant of the previous one, is to put customers with DG systems on special rates for both electricity purchases and electricity sales, rather than to continue to bill the customer for total consumption under a standard retail rate. Base service is provided under a "parallel generation" tariff that includes a fixed monthly customer charge, a demand charge, a "standby" charge, and energy charges for electricity delivered. Electricity is sold back to the utility under a "purchased power" tariff, which consists of an administrative charge, an interconnection facilities charge, and credits for both capacity and energy delivered. Customers may be provided with the option to supply electricity under a fixed contract rate, a variable rate, or a combination of both.

Contract Energy Purchases

The most sophisticated approach is to mimic the tariff designs that have been in place for years to purchase power from qualifying facilities (QFs) as defined by the Public Utility Regulatory Policies Act (PURPA). Under this arrangement, the customer is treated as a wholesale electricity provider and is put under a sales contract for the purchase of electricity, and often capacity as well. Any electricity that the customer receives from the utility is treated as firm or interruptible backup power, and the customer must contract for it accordingly. Typical options include firm or interruptible maintenance power for planned outages and firm or interruptible standby power for unscheduled outages. These arrangements are often limited to larger general service customers and/or customers who are providing all or nearly all of their electricity needs.

Common Design Parameters

Each of the following design parameters occurs in one or more of the alternative approaches described below:

- **Tariff structure:** Net metering or energy sales arrangements may be made available as (1) a rider within the standard residential or general service tariff, (2) an auxiliary tariff that is linked to the standard one, or (3) a separate standalone tariff with all rates, charges, and conditions for both purchases and sales of electricity fully specified.
- **Treatment of metering costs**: If a bidirectional meter is required, cost recovery for the meter must be specified. Some utilities require that customers pay for meter upgrades upfront, others opt for cost recovery through a fixed monthly charge, and others simply absorb the cost of the meter, with no explicit cost responsibility assigned to the customer. In all cases, however, costs for any system upgrades that are determined to be over and above what is usually required to support the installation and interconnection of DG facilities are borne by the customer, either as a direct, upfront expense, or as a contribution or revenue guarantee in aid of construction.
- **Purchase rate(s) for customer-provided generation**: A critical component of any DG tariff is the assignment of a purchase rate for electricity provided by the customer. A fundamental design parameter is whether these purchase rates will be identical to the corresponding rates for electricity provided by the utility, or whether they will be different. The following are some of the standard purchase rate assignments:
    - **The energy (per kilowatt-hour) rate that is part of the standard tariff.** This is the compensation rate associated with most traditional net metering designs. As described above, unless a utility has designed its standard tariff to recover all of its fixed costs of service in fixed monthly customer and/or demand charges, this energy rate will result in insufficient recovery of fixed costs, which then must be subsidized by other customers.
    - **Variable energy charges, specified by the company.** These rates generally are designed to correspond to the projected, forward-looking electricity production and/or purchase costs faced by the utility. As such, each rate represents an "avoided energy" cost, though a projected one, rather than an actual one. Multiple rates may be specified to correspond to peak and off-peak periods, weekdays vs. weekends, and different seasons. The schedule of rates is periodically updated to reflect changing cost projections.
    - **Fixed energy charges.** Some tariff designs allow customers to lock into a long-term fixed rate, usually as part of a contract for service. While these energy charges might be intended to correspond to long-term projected wholesale electricity prices, some utilities offer a premium, above-market rate as an incentive to support renewable DG, which is essentially a feed-in tariff.
    - **True avoided-cost energy charges.** These tariff designs attempt to compensate customers for the actual avoided energy costs that corresponded to the energy that they provided during each billing period. Simpler designs merely calculate an average wholesale cost of electricity for the billing period just ended, and apply this rate to the energy provided; more sophisticated designs attempt to assign an avoided

cost based on the actual time periods (e.g., on-peak vs. off-peak) that the energy was provided within, and the most advanced designs estimate avoided costs based on the real-time cost of electricity. This last design most closely resembles the method used by many utilities to compensate QFs under PURPA in electricity purchase arrangements. A common index used to establish the real-time cost of wholesale electricity within organized markets under these arrangements is the day-ahead or real-time hourly locational marginal price.

- **Compensation for non-energy services:** Some rate designs compensate customers for more than merely the energy provided. These are usually payments for capacity, and occur in jurisdictions where markets for electricity capacity exist. Hence, a real value to the capacity can be assigned. Customers often are paid for renewable energy credits as well.
- **Interconnection standards, codes, and guidelines:** The rules, regulations, and procedures under which a customer installs a DG source and integrates it within the electrical system must be clearly outlined and specified, including any special equipment requirements for which the customer is responsible. Interconnection rules generally appear as a section in the rules and regulations section of a utility's tariff, although sometimes they are included in a contract for service that the customer signs as a condition for entering into a net metering or electricity repurchase arrangement. The breadth and specificity of interconnection rules vary widely among utilities, ranging from a few paragraphs to more than a hundred pages in length.
- **Service options based upon customer and/or DG facility size:** Features of the electricity tariff, including the general rate design offered, the energy buy-back rate, the magnitude of fixed and demand charges, metering requirements, and the imposition of metering or other installation costs, often vary based upon one or more of the following parameters:
  - Customer class (residential, small general service, large general service);
  - Size of the DG facilities;
  - Size of customer (e.g., contract demand in kW); and
  - Service delivery point (distribution or transmission).

For example, many utilities do not charge residential customers for bidirectional or other advanced metering requirements, but do charge general service customers for these meters. In general, residential DG tariffs tend to be less complex than those offered for classes of larger customers. Also, many DG options are only made available to customers with facilities below a certain size.

SECTION 3

Alternative Approaches to Determining Payments to DG Customers

When a utility obtains surplus power from a distributed generator for resale to another customer, it is essentially engaging in a wholesale transaction. Thus, the value of the power is what power of comparable quality and certainty would be in the wholesale market. In practice, since many DG providers are QFs under PURPA, it is appropriate to understand how PURPA's concept of "avoided cost" applies.

PURPA requires utilities to interconnect with, buy power from, and sell power to QFs. Utilities must purchase power from the QFs at rates that are just and reasonable to electricity consumers, are in the public interest, do not discriminate against owners and operators of QFs, <u>and</u> do not exceed the costs the purchasing utility actually avoids. QFs are defined to include only cogeneration facilities and certain small power production facilities (namely, ones up to 80 megawatts that rely on biomass, waste, renewable resources, or geothermal resources).

To qualify, the facilities must meet fuel use, fuel efficiency, reliability, and other requirements set by FERC, and must be owned by persons not primarily engaged in the generation or sale of electric power other than from such facilities. Avoided cost is defined as the cost to the utility of energy that "but for the purchase of electricity from such cogenerator or small power producer such utility would generate or purchase from another source."[6]

Often avoided costs are determined administratively by state PUCs, with oversight by FERC. In such cases, regulators need to exercise caution not to overestimate the costs, to avoid inappropriately increasing the rates utilities and their customers must pay for power from QFs. When PURPA was passed, and for many decades thereafter, avoided cost was understood to mean that if a utility had more generating capacity than it needed to meet its peak demand, its avoided cost was the short-run marginal cost of additional fuel needed to generate an additional kWh of power. If the utility was short on generating capacity, avoided cost meant the long-run marginal cost of the most economic source of new supply.

Yet in recent years, some state regulators have included in avoided costs both the long-run marginal costs of adding new generating capacity and the short-run fuel cost of operating existing capacity. State regulators also have based avoided cost estimates on technology with high capital costs (e.g., nuclear and baseload coal) instead of on technology with low capital costs (e.g., natural gas-fired peakers).

In a 2010 order clarifying its PURPA regulations, FERC determined that in estimating avoided costs, states can recognize constraints on utility purchases of energy and capacity created by state requirements to purchase certain amounts of renewable energy.[7] This amounts to an

[6] 16 U.S.C. 824a-3.
[7] *California Public Utilities Commission*, 133 FERC ¶ 61,059 (2010), reh'g denied 134 FERC ¶ 61,044 (2011).

acknowledgement that renewable resources are frequently more expensive than other supply options (e.g., natural gas-fired generation). If state renewable mandates raise utility costs, FERC says it is acceptable to reflect this in QF purchase rates.

In the same "clarifying" order, FERC also determined that states could administer "tiered" avoided costs.[8] This means that rather than estimate the true marginal cost of new supply on the utility's system,[9] states can impose multiple avoided costs, one each for a set of discrete technologies. If a state has legislated mandates for discrete renewable energy source technologies (e.g., wind, distributed photovoltaic, central station photovoltaic, fuel cells, biomass-derived synthetic fuels), the state can administer an avoided cost for each. Where the cost of most of these technologies is above market (i.e., above the clearing prices that come out of organized wholesale markets in which all generation types are allowed to bid), the effect of this kind of avoided cost unbundling is to raise the prices utilities pay for renewable power.

FERC also determined that states could factor in any "real costs" that utilities face in purchasing energy and capacity.[10] What FERC may have had in mind in elaborating this factor was the cost of new transmission lines needed to bring wind power from the places where the wind blows to the places where people live. These are huge additional costs, which in many cases would not be incurred but for the state renewable resource mandates. Again, FERC enlarged the concept of avoided cost to pass these costs on to consumers.

All three of these determinations represent a potentially costly (for utilities and consumers) evolution in regulatory policy away from the original understanding of avoided cost, which was simply the incremental cost of the most economic source of additional supply to the utility. FERC's 2010 determinations mean that avoided cost can now be used as a tool to promote renewable resources, regardless of the cost, when combined with renewable portfolio requirements in a low growth environment.

To compound matters, FERC recently determined that utilities might not unilaterally curtail QF purchases governed by power purchase agreements during periods when electricity usage is low and the utilities do not need QF power, presumably absent explicit contractual rights to curtail the purchases in such circumstances. Impliedly according to FERC in such cases, PURPA requires utilities to buy QF power—and customers to pay for it—whether the utility needs the power or not.[11]

Social Pricing Is Incompatible with the Regulatory Compact

Many DG interests today argue that the benefits DG installations provide to utility systems and to society are very large and that such benefits should be used to offset a substantial portion of the costs utilities incur to serve DG customers. In effect, this is an argument that the benefits of DG should be priced on the basis of its *value*, while the benefits of electricity service should be priced based on its *cost*.

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[8] Ibid.
[9] A utility has only one marginal cost of supply.
[10] Same as footnote 2, supra.
[11] *Idaho Wind Partners 1, LLC,* 140 FERC ¶ 61,219 (2012).

This is mixing apples and oranges. Rate-regulated utilities are able to recover only those actual costs that the utilities experience during “test years.” These costs make their way into required revenues and are recovered in rates controlled by state regulatory commissions. This is the construct that investors rely on when they provide capital to investor-owned electric utilities. This also is the construct assumed in U.S. Supreme Court decisions establishing standards for just and reasonable rates. Utility rate practices do not account directly for costs or benefits of various externalities of the provision of electricity.

Payments to Customers With DG Should Be Based on Directly Measurable Avoided Costs From the Utility’s Perspective

It follows that to the extent to which distributed generators provide benefits to the utility, such benefits should be measured and compensated in terms of reductions in the utility’s cost of service. This can include reductions in fixed costs (e.g., generating, transmission, and distribution capacity) that the utility may avoid or defer because of the presence of a distributed generator on its system. It also can include reductions in variable costs (e.g., fuel) that the utility may avoid. However, it should not include the value of other benefits (e.g., job creation) that do not reduce the utility’s revenue requirements. Such benefits relate to costs that are presently outside (external to) the cost-of-service system. Indeed, they are external to the entire market economy.

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Distributed Generation: How Green? How Efficient? How Well-Priced?

A close look at the details of state and local programs in support of distributed generation raises some questions about the whether the promotion of green DG actually advances environmental objectives, especially when it takes place in a context of 'net metering' and flat residential electricity rates. It is time to reassess where we are going and to calibrate our pricing and policies to make certain that our efforts are carrying us in the right direction.

Ashley Brown and Louisa Lund

A backwards-spinning electricity meter driven by a rooftop solar panel is a powerfully appealing image for a public increasingly attuned to environmental, reliability, energy efficiency, and self-sufficiency considerations. Thus, the promotion of "distributed generation" (DG) has substantial public appeal. Not surprisingly, therefore, throughout the country, various mechanisms such as mandated access, subsidies, net metering programs, solar and other renewable energy credits, feed-in tariffs, and distributed generation requirements embedded within renewable portfolio standards are all being deployed to promote and support DG. DG is generally defined as smaller-scale generation intended primarily for self-consumption at the premises of end users, who are connected directly to the

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distribution system for the sale of any excess energy that is produced. In practice, solar power, particularly rooftop installations, is the predominant form of energy being promoted through DG programs, although the policies are not necessarily limited to it. Utilities in many areas are struggling to keep up with the demand for new interconnections stimulated by these programs.

In theory, distributed generation has the potential for multiple benefits, including reduced congestion on transmission lines, increased reliability, and possible reductions in energy losses through the transmission and distribution system. Above all, it is often assumed (sometimes explicitly and sometimes implicitly) that "distributed generation" means renewable, low-carbon energy. For many programs nationwide, the wish to promote green energy is the driving force behind support for distributed generation.

Those theoretical green benefits, however, are neither inherent nor certain. There is some evidence that the anticipated benefits are offset by program costs; potential perverse incentives created with respect to energy conservation, energy efficiency, and technology optimization; and socially regressive cost allocations. Given the importance that green considerations have in driving support for distributed generation, it is worthwhile to examine carefully the environmental implications of distributed generation programs as they are typically implemented.[1] A close look at the details of state and local programs in support of distributed generation raises some questions about whether the promotion of green DG actually advances environmental objectives, especially when it takes place in a context of "net metering" and flat residential electricity rates.

When the context for a distributed generation program is an overall statewide RPS, the result is a zero sum game.

I. Is Support for Distributed Generation Cost-effective as a Way to Promote the Use of Renewable Energy?

To the extent that support for distributed generation is motivated by environmental concerns, there is no clear policy basis for providing more support for green distributed generation than for central renewable generation. But that is exactly what seems to be happening in many cases. Distributed generation programs are often an add-on or carve-out in a larger framework of a statewide RPS or other system of support for renewable energy. The very fact that distributed generation programs need additional support within an RPS framework suggests that central generation of renewables is likely cheaper than renewable DG—and further evidence for this can be found in the fact that many of the programs intended to support distributed generation come with pre-set limits on the amount of generation to be supported. When a government establishes a program but sets a limit on how much it can be used, that constitutes a *de facto* admission that policymakers are very uncertain as to the benefits that are to be gained, so they are "cutting their losses" up front. When the context for a distributed generation program is an overall statewide RPS, the result is a zero sum game in which the distributed generation requirement itself does not increase the overall share of renewables in the electricity system—it merely offsets renewable requirements that would otherwise be fulfilled by central renewables.

II. What Effect do Incentives for Distributed Generation Have on Energy Conservation and Energy Efficiency?

This is a complex question, but one that could yield surprising, and, from an environmental perspective, counterproductive results. Certainly, the same

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environmental concerns that motivate support for promoting renewable DG would favor conservation and end use efficiency. There is, however, a possible conflict between pricing incentives intended to promote DG and rate designs likely to stimulate more efficient use of energy. The conflict can be resolved, as we discuss in the concluding section of this essay, but only by diluting some of the incentives for renewable energy.

The conflict between DG and energy conservation/efficiency is rooted in the fact that any use of distributed generation will cause a decline in the revenues being collected by local distribution companies. That occurs, of course, because when self-produced energy is being consumed, the customer is paying nothing for distribution services, other than fixed charges. In addition, for excess energy[2] derived from DG, when payment for that energy is made by net metering, or "running the meter backward," the outcome for the distributor is even more severe, since the practical reality of net metering is that the DG owner is effectively being paid the retail price, which includes not only the energy, but also the costs of transmission and distribution as well. While energy payments are economically justifiable, as is economic recognition of transmission savings,[3] it is very difficult to find any reasonable basis for including distribution costs in the compensation paid DG providers, when, in fact, they provide no such services and, naturally, incur no costs for the services they don't provide. Indeed, DG providers continue to rely on the distributor for distribution services. Thus, in any given month, a distributed generation customer might pay only the "fixed" portion of their bill—the part not proportional to energy use—and be paid themselves for the full retail value of any electricity they produce in excess of their usage—including charges associated with transmission and distribution, along with the wholesale cost of energy.

There is, however, a possible conflict between pricing incentives intended to promote DG and rate designs likely to stimulate more efficient use of energy.

This "net energy" approach creates problems for utilities, because it asks them to reimburse the customer an amount greater than the utility's cost savings. When a house with a solar panel on it, for example, sells excess electricity back to the utility, it is at best allowing the utility to save money on wholesale energy costs and perhaps transmission costs—it does nothing to reduce the utility's distribution costs. So if the utility pays the customer at the full electricity rate, the utility is guaranteed to lose money on distributed generation. Not surprisingly, distribution companies will seek to protect themselves from revenue erosion and will pass the responsibility for making up the delta revenue to the balance of their customers. The utilities fear that if they raise the charges tied to electricity usage, they will create a vicious cycle in which more and more users opt out, and the whole cost of the distribution system will need to be borne by an ever-shrinking customer base. Given these concerns about demand elasticity and further revenue erosion, distributors are likely to pass those costs through as fixed, rather than variable, costs, in order to best assure their full recovery. That is precisely where the potential for serious conflict between environmental objectives and the use of DG to accomplish them arises.

The problem here from a green point of view is not the inherent subsidy (subject to the questions about cost-effectiveness raised above), but the more subtle question of how this is likely to play out in terms of its impact on electricity pricing. As we discussed above, utilities are likely to try to solve the financial problems created by net metering by trying to put more costs into the "fixed" portion of the bill that customers pay even if they use no electricity. Regulators, perhaps sharing concerns about revenue erosion, but certainly constrained by the fact that the losses were caused by implementing public/regulatory policy regarding the promotion of

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DG, are highly likely to go along. The ironic result would be that less and less of the electricity bill is tied to actual usage, with the anti-green result that the rewards for energy efficiency, energy conservation, and distributed generation itself become smaller and smaller as more and more costs are shifted to the one part of the bill that everybody has to pay without regard to the level of consumption. In short, the fundamental environmental principle, "polluter pays," which in electric pricing means greater emphasis on the part of the bill that rises with consumption, will be violated in the name of promoting "green energy." Irony seems an inadequate word to describe that fundamental contradiction.[4]

III. Do Current Rate Structures Discourage Customers From Adopting the Most Beneficial Technologies?

Compounding the distortionary impact of net metering is the use of flat retail rates for electricity. In many localities, rates for compensating distributed generation are based on old-fashioned "dumb" meters that don't provide information about when energy was produced. There is a big difference, from the utility's point of view, between the value of energy "fed in" to the system at a time of peak demand, when wholesale energy prices are high, and the value of energy provided when demand and prices are low.

In this case, it's not clear whether providers of distributed generation are more likely to be overcompensated or undercompensated—a good solar installation churning out energy at peak hours might well be under-compensated based on average rates that don't reflect the real-time value of the energy being provided to the grid. The rates also fail to reflect transmission savings that DG might enable. What is clear is that incentives are not being provided to support customers in choosing the most valuable forms of distributed generation. Pricing that reflected the real-time value of wholesale energy might well result in distributed generation developing in new and exciting directions, including creative uses of energy storage that might help to ensure that distributed generation electricity is provided to the grid at the time when it would do the most good.

In short, the fundamental environmental principle, "polluter pays," will be violated in the name of promoting "green energy."

From a technological point of view, therefore, the use of flat rates for electricity has a perverse effect on the development and deployment of two very important technologies: smart meters and energy storage. There are three fundamental values associated with smart meters. The first, of course, is to enable much more efficient utility operations. The second is to enable more efficient use of energy by end users, and the third is to deal effectively with distributed energy, from both economic and safety points of view.[5] The use of net metering (insensitive to when energy is produced), of course, largely negates the potential advantages of smart meters in encouraging more efficient energy consumption and distributed generation production, since the incentive to provide energy to the grid at high-value times of day is removed. The other technology adversely affected by net metering is energy storage. If DG were compensated on a real-time basis, its investors would be incentivized to deploy storage technology in order to maximize the value of what they produce. Given the critical stage of development in which energy storage technology currently finds itself, that would provide a boost to a technology with great promise for efficiency improvements. Indeed, it is almost perverse to promote an intermittent generation technology, such as distributed solar, while discouraging the development and use of the very technology that will enable solar to be highly reliable. Real-time pricing of DG would fix that gap and is

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arguably in the best long term interest of intermittent resources.

IV. Which Customers are Most Likely to Bear the Cost of Distributed Generation Programs?

To the extent that the above concerns are not addressed, it is worth asking ourselves who will bear the brunt of any inefficient choices we make with respect to DG. There is a socially regressive aspect to passing on additional costs and delta revenue losses attributed to DG to the balance of customers who do not have DG facilities. While certainly not all DG providers are affluent, nor will all affluent customers invest in DG, there is a likelihood that DG investors will on average be higher-income than other customers. It is unlikely that many low- to moderate-income households will have the financial resources and desire to invest in DG. Thus, any additional cost or delta revenue loss attributable to DG that is passed on to the balance of customers has a high probability of being a wealth transfer from the less affluent to the more affluent. This socially regressive result is compounded by the fact that fixed costs are incurred equally by all customers, whereas variable costs are passed on based on levels of consumption. Hence poor customers who use small amounts of electricity for lighting, refrigeration, and perhaps entertainment, will pay the same costs as wealthy customers with a plethora of appliances consuming electricity.

Of course, the concerns above are not necessarily reasons to abandon support for distributed generation. They do, however, suggest two areas worth further thought for those concerned with a green agenda. First, if we believe that a transition to greener energy is both vital and likely to be expensive, it is important to be efficient in our green energy choices. To this end, it would be worthwhile to more clearly understand the relative costs of distributed generation compared to alternative sources of green energy—how much of a premium are we paying for distributed generation under current practices? How much should we pay, and what are we trying to accomplish with this money? Are we fostering an infant industry? If so, how do we decide when to stop? Do we need DG in order to reach renewables goals in the face of NIMBY opposition to larger projects?[6] Are the other benefits of DG in terms of reliability significant, and how can we quantify them?

There is a socially regressive aspect to passing on additional costs and delta revenue losses attributed to DG to the balance of customers who do not have DG facilities.

Second, we should think carefully about how distributed generation is incorporated into overall electricity rates, particularly how it interacts with "net metering" and flat rate electricity charges. Does it magnify or reduce the problems of current rate systems in terms of incentives for efficiency and demand response? Structuring DG compensation well could alleviate a number of the potential negative outcomes of DG programs—the "anti-green" and socially regressive results of DG pressures on electricity pricing, as well as the disincentives current pricing schemes create to the adoption of efficient technologies. All of these can be avoided, or at least mitigated, by compensating DG producers at the market clearing wholesale price at the time they deliver energy, plus any transmission savings they enable. That, of course, would reflect the true economic value of what they provide. It would also eliminate the other related problem of compensating DG providers based on average costs over the billing cycle regardless of whether they are producing on or off peak.[7] The solution to this problem, of course, lies in the deployment of smart meters, which are capable of measuring energy inputs and outputs on a real-time basis.

Proponents of DG have, for the most part, opposed such pricing schemes. They argue that such arrangements will make DG less attractive financially and

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therefore reduce the scope of its deployment. They are, of course, probably correct in that assertion. The more money thrown at any technology, the more likely it is to be deployed. Thoughtful deployment of DG, however, is a far more complex matter than simply adopting financial incentives for DG investment. Public policy demands that resource deployment be consistent with overall system optimization and not just with the promotion of a favored technology. While notions of system optimization may well include both the internal economics of the network, as well as externalities such as the environment, the practice of simply pricing a particular resource in order to promote it, as opposed to pricing it to reasonably reflect its overall value, constitutes a leap of faith that is virtually incapable of justification.[8] It is, therefore, important to facilitate the entry of DG into the marketplace, but to do so in economically justified ways. For

Legislators in states such as Massachusetts and California recognized that there were potentially perverse consequences.

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example, it might be possible to address these problems by changing the compensation of distributed generation to include only the avoided costs of energy and transmission services and to reflect real-time energy prices. This might mean that it would be harder for homeowners to earn a good return from their distributed generation investments. But this may be a necessary risk. If we are promoting renewable distributed generation for purposes of environmental benefit, then we need to link that to pricing. What we are doing now is exactly the opposite. We are producing anti-green pricing to compensate for promoting green technology.

As things currently stand, the desire to have a robust program of support for green distributed generation may be pushing many utilities and regulators into supporting programs that, at best, are not cost-effective and at worst create perverse incentives that work against the green goals that motivate them. When it comes to distributed generation, we need additional clarity on what we are trying to achieve and whether distributed generation is the best way to get there. Legislators in states such as Massachusetts and California, despite their aggressiveness in promoting DG, recognized that there were potentially perverse consequences, because they capped the amount of energy required to be purchased. With the experience that we have now had, it is time to reassess where we are going and to calibrate our pricing and policies to make certain that our efforts are carrying us in the right direction.■

Endnotes:

1. As noted earlier, not all distributed generation is solar, nor renewable, for that matter, but since carbon neutrality is a major, although not necessarily the only, driver of policies promoting DG, much of the focus of DG policy revolves around renewable energy.

2. Excess energy, for purposes of this article, is defined as DG-produced energy in excess of that being consumed at the premises wherein the DG facility is located, energy which is customarily sold into the distribution system.

3. Since DG feeds directly into the distribution system, the purchase of DG reduces the need for transmission services and, therefore, reduces the costs that a distributor would otherwise pass on to their customers. This benefit is even greater when the distributor is incurring congestion costs on the transmission grid, as DG can actually serve to relieve congestion and thereby reduce system costs.

4. One could make the same argument about de-coupling to remove the utility disincentive to provide demand-side management or energy efficiency programs. Energy efficiency and DG are not, however, the same. Efficiency programs obviate the need for generation, increase end use efficiency, and constitute the most environmentally benign source of energy, negawatts. In short, society, over the long run, saves both energy and money. DG, on the other hand, constitutes simply another supply-side resource requiring a revenue stream. While DG may or may not be preferable to other sources of generation for economic or environmental reasons, it does not save energy. It may cause the utility the same kind of revenue erosion as demand side management, but that is not inherently true, as it is with conservation and energy efficiency. The revenue effects of DG are largely, although not entirely, the result of how DG is priced. Thus, comparisons of the rate effect of DG with energy efficiency programs are misplaced.

5. Dumb meters do not reveal the presence of stray voltage on the grid when work is being done, while smart meters do. Thus, distribution workers are better protected by smart rather than dumb meters.

6. NIMBY may, in fact, not be unique to large projects. Many communities have contemplated or are likely to contemplate the promulgation of land use, noise, and aesthetics regulations to govern distributed generation.

7. The problem of compensating DG by reversing the meter based on the net at the end of a billing cycle is not a trivial one. The effect is to pay the producer the same price on- or off-peak, a result devoid of any basis in costs, system benefits, externality benefits, or any other economic logic, other than simply subsidizing DG.

8. The authors are not arguing that no subsidies are ever justified. Certainly, they may be required to incentivize research and development, and perhaps other limited purposes. That is a subject beyond the scope of this article. What is not a good idea, however, is merely subsidizing a resource to favor a particular technology without fully analyzing the overall effect of doing so, both economically and socially.

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VALUE OF THE GRID TO DG CUSTOMERS

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Value of the Grid to DG Customers

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VALUE OF THE GRID TO DG CUSTOMERS

Some advocates of distributed generation (DG) claim that the DG customer derives no benefit from being connected to the host utility's distribution system.[1] While it is easy to say that a DG customer is "free from the grid," it is simply not true – even for a DG customer or a micro-grid that produces the exact amount of energy that it consumes in any given day or other time interval.[2]

This paper describes how a DG customer (or a micro grid) that is connected to the host utility's distribution system 24 x 7 utilizes grid services on a continual, ongoing basis. The issue is to recognize the value of the grid and discuss an appropriate fee that a DG customer should pay for use of these grid services. We refer to this as the "value of the grid" and include four cost components – the typical "fixed" costs associated with (i) transmission, (ii) distribution, and (iii) capacity, and the costs of (iv) ancillary and balancing services that the grid provides throughout the day for the DG customer. *There is a separate and important question about how much DG customers should be paid, or credited, for any excess electricity that they generate and inject into the grid. This paper does not address the "excess energy" issue.*

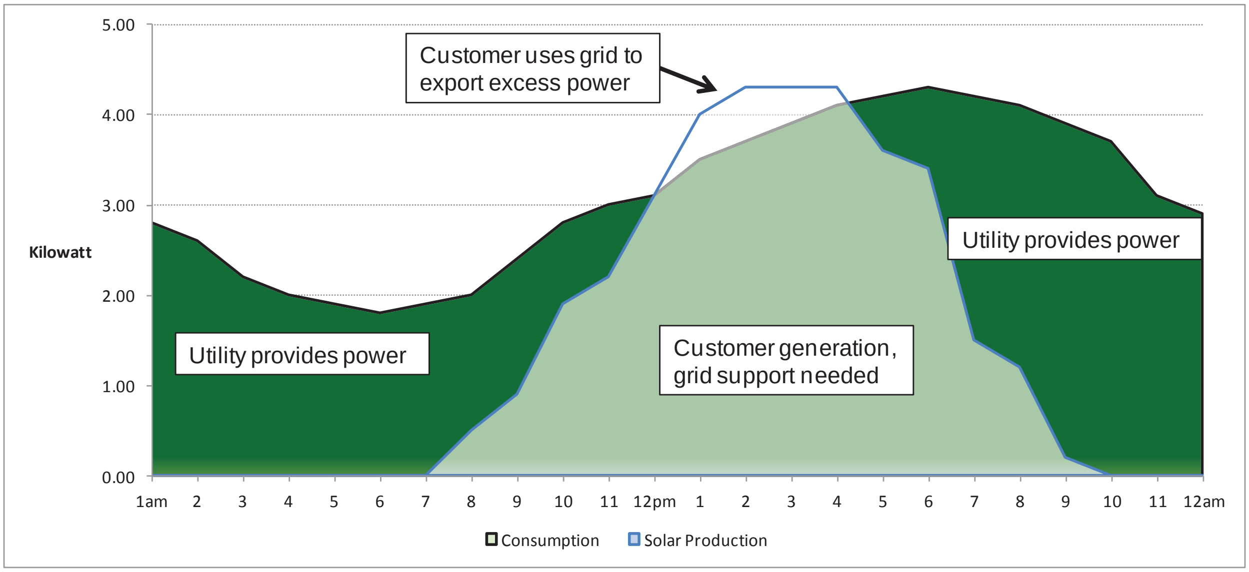
THE BENEFITS OF REMAINING CONNECTED TO THE DISTRIBUTION SYSTEM

Consider a residential or small commercial customer with solar PV panels on his rooftop. Figure 1 displays a typical hourly pattern of energy production and consumption for such a customer. The green area is the energy consumed on-site and provided by the host utility. The blue areas combined are the energy produced on-site by the solar panels. The light blue portion is the excess energy injected into the utility's distribution system. The key takeaway from this graphic is that the customer's consumption and generation are almost never equal; consequently, most of the time the customer is using the external power system to balance its demand for electric energy with its on-site production. In most cases the customer will be taking energy from the grid during many hours of the day. For example, the customer depicted in Figure 1 takes power from the grid in all hours except from noon to 5pm.

1 The recent Forbes article, "Distributed Generation Grabs Power form Centralized Utilities," August 8, 2013, ignores and fails to mention the grid services that are provided to DG customers continuously by the host utility.

2 The term, DG, refers to small retail customers with on-site generation that are net metered.

Figure 1 – Typical Energy Production and Consumption for a Small Customer with Solar PV



Customers with any type of DG that are connected to the grid will be utilizing external grid services to:

- balance supply and demand in sub-second intervals to maintain a stable frequency;
- match load with on-site generation over longer time intervals;
- time-shift energy from the hours of excess generation to the hours of deficit generation (i.e., storage service);
- provide the energy needed to serve the customer's total load during times when on-site generation is inoperable due to equipment maintenance, unexpected physical failure or prolonged overcast conditions (i.e., backup service);
- provide voltage and frequency control services and continuous high quality AC wavelengths.

Clearly, even if the customer's total energy production over some time interval (*e.g.,* a monthly billing cycle) exactly equals its consumption over that same interval, that customer is still utilizing at least some, if not all, of the above grid services during that time interval.

So what value does a customer with solar PV generation derive from remaining connected to the grid? Let's begin by first examining the charges that a typical residential customer consuming an average of about 1000 kWh per month (average consumption based on EIA data and rounded) will pay for grid services, <u>excluding the charges for the electric energy itself</u>. These are typically referred to as "fixed" charges that are designed to allocate to the customer its fair share of the

fixed costs associated with the transmission system, the distribution system, balancing and ancillary services, and the utility's (or the retail supplier's) investment in generation capacity. As stated earlier, the electric energy charges designed to recover the cost of the energy (kWh) consumed by the customer (including the associated transmission and distribution losses), are excluded here. Table 1 illustrates these charges for a typical residential customer.[3]

Table 1 – Non-Energy Charges Paid by a Typical Residential Customer on a Retail Tariff

Average Residential Customer: Non-Energy Charges as Percent of Typical Monthly Bill	
Average Monthly Usage (kWh)*	1100
Average Monthly Bill ($)*	$110
Typical Monthly Fixed Charges	
Ancillary/Balancing Services	$1
Tranmission Systems	$10
Distribution Services	$30
Generation Capacity ^	$19
Total Fixed Charges for Customer	$60
Fixed Charges as Percent of Monthly Bill	**55%**

*Based on EIA (2011)
^The charge for capacity varies depending upon location. This is just an estimate.

In this example, for a residential customer with average monthly usage of 1000 kWh, the average monthly bill is about $110 per month (based on EIA data). About half of that bill (*i.e.,* $60 per month) covers charges related to the services provided by the grid (including the charge for generation capacity). Since residential retail rates are almost always designed to recover a large portion of the power system's fixed costs through kWh charges, the DG customer will avoid paying some or all of his fair share of the costs of grid services. Ultimately these costs, which are significant, will be shifted to other retail customers. In this example, each DG customer shifts up to $720 per year in costs to other retail non-DG customers. To put this into context, if 50% of the residential customers in a given utility service territory had DG, the other 50% of non-DG residential customers in the service territory would experience bill increases of up to

3 We recognize that other charges could also be added to this list but the focus of this paper is on the grid services that are provided by the host utility.

55% – from $110 per month to $170 per month. It is plain to see that this cost shift is simply not fair.

We believe that DG customers must pay their fair share of the cost of the grid and that pushing this cost onto non-DG customers raises serious cost allocation and fairness issues. Indeed this is one of the key issues in the current debate over net metering.

To illustrate the value of these services, assume that a solar PV customer does pay the charges for remaining connected to the gird of about $60 per month.[4] To put this "cost" into context, what would it cost this customer to "self provide" these services? Consider the extreme case where the customer chooses to be free of the grid and "self provides" these grid services through some combination of energy storage and/or thermal generation (*e.g.,* a Generac home generator).

Preliminary estimates of the costs that the typical residential customer who disconnects from the grid would have to incur per month to self-provide the balancing and backup services that the grid would otherwise provide are several times higher than $60 per month. Furthermore, the cost estimate of $60 does not include the additional value associated with better voltage and frequency control and higher quality AC waveforms delivered by the grid. An isolated micro-grid or a DG system cannot provide the same quality of electrical service as a large power system.

This straightforward comparison to "self providing" grid services reveals three things. First, it does not make economic sense for a customer to "self provide" the balancing and backup services that the grid provides. Second, these grid services are needed and have value. Third, it is unfair to shift the cost burden to non-DG customers. Obviously, DG customers should pay their fair share of the cost of the grid services that the host utility provides.

ECONOMIES OF SCALE ASSOCIATED WITH POWER SYSTEMS

In many ways the growth of DG and micro grids today goes full circle back to the early days of the electric power industry. Initially power systems were isolated and each served its own service area. As service areas expanded, utilities began to interconnect. PJM was the first entity

4 The actual charges will be somewhat less than those shown in Table 1 because the capacity charge for generation could be lower if the DG customer's on-site generation reduces its peak demand.

to interconnect utilities for reliability purposes and to centrally provide balancing services. This evolution was driven by the substantial economies of scale which still continue today as ISO/RTO markets continue to grow and expand.[5]

These interconnection entities developed for a reason. When a small power system interconnects with a larger one, all members of the resulting combined entity benefit. However, it has been observed that the small system benefits disproportionately more than the incumbent members. This phenomenon is even more pronounced when a micro-grid interconnects with a power system

DG Market is Growing, Pricing it Right is Key

Although net metering was a convenient vehicle for kick-starting the DG market, there are now serious questions among state policy makers regarding its continuation and needed reforms. *One main concern, addressed by this paper, is that the net metered customers are avoiding payment of their fair share of the grid services described earlier, thereby causing those lost revenues to be recovered from other customers.* As also demonstrated in this paper, these "grid" costs are quite significant – about 55% of the monthly electric bill for a residential customer as demonstrated in Table 1. Although this may not have been a major problem when the DG market was in its infancy, sending the wrong price signals to both customers and to the DG industry is a major problem as the DG market rapidly grows and develops.

Several alternative approaches to net metering are under examination across the nation.[6] Three illustrative approaches that ensure that a DG customer that uses grid services pays for its share of the costs of these services (rather than having these costs recovered from other utility customers) are the following:

- Redesign retail tariffs such that they are more cost-reflective (including using a demand charge),
- Compensate the customer for its gross (*i.e.,* total on-site) generation while separately charging it for its gross consumption under its current retail tariff, and

5 Entergy's decision to join MISO is a recent example.

6 Distributed generation and net metering were very hot topics at the Summer 2013 NARUC meetings with at least five panel discussions addressing them.

- Administer T&D "standby" charges to DG customers.

These three approaches are illustrative only and are summarized below.

APS: Redesign Retail Tariffs. To address the fundamental issue that a residential customer with rooftop solar should get compensated at a fair rate for the power it exports (sells) to the grid and also pay a fair price for its use of grid services, APS is proposing two options for these DG customers.[7] The first option requires the customer to take service under an existing demand-based rate schedule. The demand charge would cover a reasonable portion of the cost of grid services. The second option allows the customer to choose an existing APS rate schedule for his total electric consumption and APS will purchase all of the customer's rooftop solar generation at market rates. This option ensures recovery of grid services and sends a more accurate price signal to DG customers. It is also conceptually similar to what Austin Energy has put in place which is described next.

Austin Energy: Separately Meter On-site Generation and Consumption. Austin Energy has implemented a solar tariff that compensates its DG customers for their gross on-site generation while also charging customers for their gross consumption.[8] This approach effectively ensures that the cost of grid services are recovered from DG customers.

Austin Energy's proposed solution is to charge each retail customer for gross consumption under its existing retail tariff and to separately compensate the customer for energy produced at the utility's or retail suppliers' avoided cost. PURPA (under Title II) provides an established precedent for such compensation.[9] This approach requires a separate meter for on-site generation.

Dominion. T&D Standby Charges for DG Customers. Any residential net metered DG customer with a system between 10kW and 20kW is required to pay a monthly transmission

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7 APS conversation, July 2013.

8 Rabago, K.R., *The „Value Of Solar" Rate: Designing An Improved Residential Solar Tariff*, Solar Industry, February 13, 2013. Available at www.solarindustrymag.com.

9 Although PURPA only applies to generating resources that are Qualified Facilities (QFs), this condition has not been applied if the customer receives a credit on its electric bill, rather than a monetary payment for its generated energy.

standby charge of $1.40 per kW and a monthly distribution standby charge of $2.79 per kW. This was effective April 1, 2012. Generation standby charges were not approved.

These new tariffs and proposed approaches demonstrate how critical it is for DG customers to pay their fair share of the cost of grid services – and sooner rather than later.

About IEE

IEE is an Institute of The Edison Foundation focused on advancing the adoption of innovative and efficient technologies among electric utilities and their technology partners that will transform the power grid. IEE promotes the sharing of information, ideas, and experiences among regulators, policymakers, technology companies, thought leaders, and the electric power industry. IEE also identifies policies that support the business case for adoption of cost-effective technologies. IEE's members are committed to an affordable, reliable, secure, and clean energy future.

IEE is goverened by a Management Committee of electric industry Chief Executive Officers. IEE members are the investor-owned utilties who represent about 70% of the U.S. electric power industry. IEE has a permanent Advisory Committee of leaders from the regulatory community, federal and state governement agencies, and other informed stakeholders. IEE has a Strategy Committee of senior electric industry executives and 30 smart grid techology company partners.

Visit us at: **www.edisonfoundation.net/IEE**

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IEE | INNOVATION ELECTRICITY EFFICIENCY

An Institute of The Edison Foundation

CCIF

Critical Consumer Issues Forum

All NARUC & NASUCA Annual Meeting attendees are invited to…

CCIF's 4th Annual Kickoff Forum

Distributed Generation: Consumer-Focused Options for Policymakers & Regulators

Saturday, November 16, 2013 ♦ 2:00–5:00pm
Orlando Hilton Bonnet Creek ♦ Orlando, FL

The Critical Consumer Issues Forum (CCIF) invites you to join us in Orlando for our 4th Annual Kickoff Forum, which will build on the consensus framework and principles on distributed generation (DG) that were developed by CCIF earlier this year (report available at *www.CCIForum.com*). To dig deeper into the complex topic of DG, areas of discussion will likely include:

- Value of a Safe, Reliable, and Resilient Grid to Enable DG Options for Consumers
- DG Market Development and Deployment
- DG Cost Allocation Approaches and Best Practices
- Consumer Protections, Complaint Resolution, and Education

This dialogue will help shape CCIF's work in summits next spring, at which commissioners, consumer advocates, and electric utility representatives will continue the discussion, develop options for consideration by policymakers and regulators, and form consensus where possible. As we begin the effort to build on the CCIF framework on DG and further assist policymakers and other stakeholders in evaluating these challenging issues, we encourage your participation.

Registration. Registration will open no later than September 3rd at ***www.CCIForum.com/ccif-events/registration***. **Please register by November 6th.** There is no charge to participate, but registration with CCIF is required. Please make travel plans accordingly.

Hotel Stipends. EEI is offering a limited number of stipends to participating state commissioners and consumer advocates for a 1-night credit at the Orlando Hilton Bonnet Creek at the NARUC conference rate (or reimbursement for 1 night at an equal or lower rate at another hotel). Please indicate interest in a stipend during registration, and eligibility will be confirmed soon thereafter. All registrants are responsible for making their own hotel reservations, including any additional nights to attend the forum.

For More Info. Information about CCIF and this meeting is posted at ***www.CCIForum.com***. You may also contact Katrina McMurrian, CCIF Executive Director, by e-mail at ***katrina@CCIForum.com*** or by phone at ***337-656-8518***.

Registration opens September 3rd at *www.CCIForum.com/ccif-events/registration.*

This event is not a part of the agendas of the 125th NARUC Annual Meeting or 2013 NASUCA Annual Meeting.

ELECTRIFICATION CAMPAIGN

EEI Fall Board and Chief Executives Meeting, September 2013

EEI Electrification Initiative:

Electrification of the transportation sector represents an opportunity for utilities to expand their market, to improve operational efficiencies and to proactively engage with customers to provide new services and solutions. Given the breadth of benefits to be realized, it follows that a program designed to promote electrification would touch all business units of the organization, from customer service to operations to rate planning. To address this complexity, EEI is taking a multi-tiered, cross-functional approach.

At a strategic level, *Electrification: The Path Forward* describes EEI's focus on advancing the business strategy to ensure an electrification program becomes fully integrated across the organization. At a tactical level, the *Electrification Action Plan* outlines our efforts to develop the tools and resources necessary to effectively interface with customers and educate policy makers and regulators. As an important first step – and to lead by example - EEI is working with representatives from your companies to electrify utility fleets. Finally, we are using communications campaigns to leverage the voice of the customer and build momentum among stakeholders to promote the value of electricity as a transportation fuel.

The Path Forward:

The CEO Electric Transportation Task Force discussion will focus on why electrification is important, offer some strategies on how to implement a successful electrification program, and underscore the importance of customer engagement and communication.

Action Requested:

- Given the complexity, and cross-functional nature of these programs, we urge you to consider your organization from a holistic perspective: how could an electrification program be implemented so that benefits and costs from all business units are taken into account?
- EEI will be contacting a representative within your organization to share best practices and strategies on utility fleet electrification. Please allocate the necessary time for your representative to participate in this important collaboration.

EEI Board Lead:

James J. Piro, CEO and President, Portland General Electric

Additional Resources:

Electrification Action Plan -
http://www.eei.org/issuesandpolicy/CEOBoardBookRestricted/EEI_Electrification_Action_Plan-Final.pdf

ELECTRIFICATION: THE PATH FORWARD

EEI Fall Board and Chief Executives Meeting, September 2013

Why Electrification?

Against the backdrop of slowing demand growth and upward price pressure – along with new competition from distributed energy resources – transportation electrification is a bright spot. Instead of taking the traditional perspective of electricity as a commodity, a proactive electrification strategy will help develop a new market for utilities and opens the door to a range of new service opportunities. It's a win-win for utilities and customers: by partnering with our customers to find electrification solutions, we can grow our business while increasing their productivity.

Incremental Load

- ☑ Additional kWh demand spreads out costs and drives down prices
- ☑ Improves system utilization

In-Road to Customer Services

- ☑ Shift to "value of service" mindset
- ☑ Opportunity to expand market share and provide energy services as unbiased technical advisor

Flexible Load

- ☑ Potential to drive customers to flexible load as a means of load response
- ☑ Fill in the negative demand created by solar and wind resources

Environmental and Economic Benefits

- ☑ Decrease customer cost and increase revenue through energy productivity
- ☑ Environmental benefits help compliance
- ☑ Electricity is a local economic stimulus

Pathway to Electrification

An electrification program is cross-functional: it unlocks benefits across a number of different business units. An example: adding heavy duty plug-in hybrid trucks with power export capability to utility fleets would benefit the fleet itself, but could also reduce planned outage downtime and increase customer satisfaction scores. However, these latter benefits would only be recognized outside the fleet business unit (Figure 1). Furthermore, lessons learned by the fleet group will only be shared externally if there is a cross-functional strategy in place. For this reason, an electrification program is truly a company-wide initiative that calls for a cross-functional, top-down approach.

Figure 1: Fleet example shows benefits across multiple business units

Key Aspects of a Successful Electrification Program

Cross-Functional
A strategic perspective with visibility into every business function is needed to fully account for all the costs and benefits, as well as shape programs, administer incentives, and align the company around promoting electrification.

Customer-Focused
Electrification is ultimately about end-use applications. A properly designed program will meet customer needs and be responsive to their input. The relationship between account managers and customers is the critical interface.

Leverage Existing Resources
An electrification program requires a re-focusing of resources, not a new organization. A matrix solution is suggested to utilize existing channels.

Leading by Example: Utility Fleets

A good place to start an electrification initiative is in our own backyard. In addition to demonstrating our leadership, the lessons learned and expertise gained from electrifying our own fleets will be directly applicable to our customers.

PG&E's work with electric power takeoff (ePTO) trucks demonstrates that the time to bring electrification technologies to utility fleets is *now*. These hybrid work trucks have a reasonable payback period today based only on fuel cost savings from eliminating idle time (Figure 2). Engine wear from idling is reduced by 69%, assuming an idle time of 5 hours a day. Furthermore, customers and crews report that hybrid trucks operate cleaner, quieter, and more comfortably than their conventional counterparts.

Conventional Truck		Hybrid Truck Advantage	
Idle time per day (hours)	**Gallons consumed idling per day**	**Idling fuel cost saved per year**	**Payback period (years)**
6	12	$14,533	**2.0**
5	10	$12,111	**2.5**
4	8	$9,689	**3.1**

Figure 2: Eliminating idle time is one of the significant advantages of electrifying utility fleets. This payback example is based on a projected 3-year average fuel price of $4.49 per gallon and assumes 2 gallons consumed per hour idling, 270 working days per year, and a $30k MSRP premium for a hybrid truck.

EEI has created a Fleet Users group to help spread this message to other member companies. The group will share best practices and strategies on how to build a business case for fleet electrification, including driving internal buy-in, identifying appropriate technologies and applications, and developing financial models and cost-benefit analyses.

The Fleet Users Group will also create an important foundation for fleet electrification in general that utilities will be able to take to their commercial, industrial, and institution customers interested in electrifying their own fleets. By cultivating our shared knowledge and expertise, we can spread the benefits of electrification to a much broader audience and build new partnerships with our customers.

DoD Base Issues

EEI Fall Board and Chief Executives Meeting, September 2013

Department of Defense (DoD) Renewable and Energy Security Goals

The DoD is aggressively pursuing the Administration's goal to deploy three gigawatts of renewable energy on domestic Army, Navy, and Air Force (AF) installations by 2025. These targets support the broader DoD goal to meet 25% of its energy needs with renewable energy by 2025.

To minimize additional costs to the taxpayers for these projects, DoD will rely upon leveraging private sector financing through its existing authorities which include: PPAs, Enhanced Use Leasing, Utility Energy Savings Contracts (UESCs), and Energy Savings Performance Contracts.

Furthermore, DoD envisions that microgrid and storage technologies, coupled with local sources of renewable power, will increase the energy security of military installations. Some leaders in the Pentagon call advanced microgrids a "triple play" for reducing installation energy costs, facilitating the incorporation of renewable and other on-site energy generation, and—combined with energy storage—enabling an installation to maintain critical loads during outages.

EEI Members Partnering with Their Military Customers

Since the EEI CEO Task Force on Energy Security was formed in 2010, the industry has encouraged the DoD to collaborate with their utilities on energy security and grid-scale renewable initiatives. EEI members have emphasized that electric companies are uniquely qualified to work with DoD in securing and strengthening its facilities' energy infrastructure. Unlike any other entity, it's in our DNA and DoD should tap into our expertise and utilize existing authorities like privatization, areawide contracts, and UESCs.

While the threat remains that DoD installations could contract with third parties on RE and energy security projects, there are encouraging signs that they see their local electric utility as their most attractive, viable partner thanks in part to the industry's outreach efforts. This discussion will illustrate some of the strategies, tactics, and collaborations that are taking shape between EEI member companies and their installations.

EEI Board Lead:

Paul J. Bonavia, Chairman and CEO, UNS Energy

DoD/Federal Energy Mandates Statues   August 2013

- ## Energy Consumption and Efficiency
  - **Executive Order 13514 (October 2009)**
    - Implement high performance sustainable federal building design, construction, operation, and management, maintenance, and deconstruction including:
      - Beginning by 2020, ensure new buildings are designed to achieve net-zero energy by 2030
      - Ensure that at least 15% of existing buildings and building leases (>5K gross sq ft) meet Guiding Principles for Federal Leadership in High Performance and Sustainable Buildings by FY '15
  - **Energy Independence and Security Act of 2007**
    - Reduce energy intensity in federal buildings by 3% annually and 30% by 2015 from FY'03 baseline
    - Each agency shall meter gas and steam no later than Oct 1, 2016
  - **Executive Order 13423 (Jan 2007)**
    - Improve energy efficiency through reduction of facility energy intensity 3% annually and 30% by end of FY '15 (2003 baseline)
  - **Energy Policy Act of 2005**
    - All federal buildings shall be metered for gas, steam, electricity

- ## Renewable Energy
  - **National Defense Authorization Act of 2010**
    - Produce or procure at of over 25% of the total quantity of facility electricity from RE sources beginning in 2025
    - Explore expeditionary use of solar and wind to provide electricity
  - **Energy Policy Act of 2005**
    - Renewable energy purchase requirements:
      - At or greater than 3% for FY2007-2009
      - At or greater than 5% for FY2010-2012
      - At or greater than 7.5% for FY2013 and each year thereafter
  - **Executive Order 13423 (Jan 2007)**
    - Consume not less by 50% of RE from new RE sources (in service after 1/1/99). Non-electric renewable resources (e.g., solar water heating) can be used to meet requirement, but all of the EPAct '05 goal must be met with RE.
    - Implement RE generation projects on agency property for agency use.
  - **Army, Navy, AF RE Goals**
    - **White House announced a DoD goal to deploy 3 GW of RE by 2025.**
      - 1 GW on Naval installations by 2020

        - 1 GW on AF installations by 2016
        - 1 GW on Army installations by 2025

- ## Acquisition of Alternative Fuels
    - **EISA 2007**
        - No agency shall enter into a contract for procurement of an alternative or synthetic fuel, including a fuel produced from nonconventional petroleum sources, for any mobility-related use, other than for research or testing, unless the contract specifies that the lifecycle GHG emissions associated with the production and combustion of the fuel supplied must be less than or equal to such emissions from the equivalent conventional fuel produced from conventional petroleum sources.

- ## Vehicle Petroleum Consumption
    - **EO 13514**
        - Reduce the use of fossil fuel by:
            - Using low GHG emitting vehicles in fleet
            - Optimizing the number of vehicles in agency fleet
            - Reducing the agency's fleet total consumption of petroleum products by a minimum of 2% annually through the end of FY 2020 (2005 baseline)
    - **EISA 2007**
        - Beginning in FY2020, each agency shall reduce oil consumption and increase alternative fuel consumption to meet the following goals:
            - No later than Oct 1, 2015, and for each year thereafter, each agency shall achieve 20% reduction in annual oil consumption and a 10% increase in annual alternative fuel consumption (2005 baeline)
                - Alternative fuels cannot be purchased if lifecycle GHG emissions are greater than emission from conventional oil.
    - **EO 13423**
        - Increase the total fuel consumption that is non-petroleum based by 10% annually:
            - Use plug-in hybrid vehicles when they are commercially available at a cost reasonable comparable, on the basis of life-cycle cost to non PIH vehicles.

President's Better Buildings Initiative -Federal Sector (Dec 2011)

- The Federal Government shall enter into a minimum of $2 billion in performance-based contracts in Federal building energy efficiency within 24 months from the date of this memorandum (Dec 2011). This include Utility Energy Services Contracts (UESCs)

- Each agency shall include its anticipated total performance-based contract volume in its plan submitted pursuant to subsection (d) of this section.
- In order to maximize efficiency and return on investment to the American taxpayer, agencies are encouraged to enter into installation-wide and portfolio-wide performance contracts and undertake comprehensive projects that include short-term and long-term ECMs, consistent with Government-wide small business contracting policies.
- Agencies shall prioritize new projects under this section based on return on investment, develop a planned implementation schedule, and reconcile all investments with actions undertaken pursuant to Executive Order 13576 of June 13, 2011 (Delivering an Efficient, Effective, and Accountable Government). Agencies shall ensure that any performance-based contracts are consistent with, and do not duplicate or conflict with, real property plans or planned capital improvements.

Fundamental Tax Reform

Tax reform priorities and legislative activity

The industry supports the goals of tax reform to simplify the U.S. tax code, broaden the tax base, and reduce rates. EEI continues to prepare to engage the Congress in comprehensive tax reform.

- Both parties support tax reform, and the House Ways & Means Committee and the Senate Finance Committee have been working towards this goal. In June, Chairman Max Baucus and Ranking Member Orrin Hatch of the Senate Finance Committee sent a letter to their Senate colleagues requesting input on their tax reform priorities. Specifically, the letter advocated for a "blank slate" approach, in which, in return for a lower statutory rate, the tax code would be scrubbed of all expenditures and other deductions except for those considered worthy of retention. Approximately 60 Senators provided varying degrees of responses to the Senate Finance Committee.

  - To help its advocacy activities, EEI has identified the most salient issues for the industry:Preserving the deduction for interest on corporate debt.
  - Ensuring that any reduction in the statutory tax rate that creates excess deferred taxes would be accompanied by a normalization patch, which would also address any investment incentives such as accelerated depreciation.
  - Maintaining low tax rates on dividends that are at parity with the tax rates on capital gains.

EEI activities

Given the complexity of the issues, it is important to engage committees and task forces as well as educate lawmakers and key members of the tax-writing committees in particular so that these important issues are addressed in any committee prints proposed by committee leadership.

In response to the Baucus/Hatch letter, EEI provided your Washington Reps with lobbying documents on our three priorities and also sent a personal letter to each Senator outlining these priorities.

As part of the EEI advocacy and education initiatives, a group of member company CFOs and tax executives will visit the Hill on September 18 to brief relevant members of Congress and staff for the House Ways & Means and Senate Finance Committees.

Also, EEI has joined some of the major coalitions focused on corporate tax reform which will help advance some of our interests, mainly in mainstream corporate tax. The industry, however, will be alone in some other issues that are only important to the power sector like normalization and excess deferred taxes.

Board Leads:

Thomas A. Fanning, Chairman, President & CEO, Southern Company
Theodore F. Craver, Jr., Chairman, President & CEO, Edison International

Revised D R A F T August 9, 2013
For Internal Discussion Purposes Only

EEI Tax Reform Principles

The shareholder-owned electric utility industry provides an essential service that powers job creation and economic growth. Our industry currently employs over 500,000 full-time employees and invests more than $80 billion per year in improving and expanding electric services to American businesses and consumers. The electric utility industry must expend significant levels of capital in the future to sustain high levels of reliability, promote economic growth, create jobs and meet environmental standards.

Federal income tax is a significant expense for shareholder-owned electric utilities. The treatment of taxes in the establishment of regulated electricity rates is an issue that distinguishes utilities from other U.S. businesses. This is so because income taxes are included in customers' rates and tax deferral benefits, such as for accelerated depreciation, provide an important source of capital. Our industry has a lot at stake in the tax reform policy debate.

Our industry supports the following key principles for comprehensive tax reform:

- The corporate income tax system should be restructured in a way that improves the efficiency and simplicity of the tax code to facilitate and foster capital investment and growth in the domestic economy and jobs.

- Our industry is open to eliminating or limiting certain preferential tax deductions and tax credits from which it currently benefits, so long as the corporate tax rate is lowered sufficiently to offset the loss of these tax provisions.

- With our industry being the most capital intensive in the country, maintaining the current federal income tax deduction for interest expense is vitally important for electric utilities. Any substantial change to the deductibility of interest on corporate debt would significantly impair the ability of electric utilities to access lower-cost capital. Such a change would therefore raise the cost of capital, negatively impacting electric consumers by raising the cost of producing and delivering reliable electricity.

- It is critical to maintain parity with respect to the tax rate for dividends and capital gains. Otherwise, the tax code would arbitrarily advantage non-dividend paying stocks over stocks that pay dividends. Our industry supports this parity along with maintaining low tax rates on dividends and capital gains.

- If energy tax incentives are eliminated, they should all be eliminated at the same time, allowing for a reasonable phase-out period. Appropriate transition rules must accompany significant tax law changes. Our industry has made substantial investment in existing property, and has made significant commitments toward new investment projects in reliance on the current tax rules. Tax reform should retain the current tax treatment for

these investments. Consideration should also be given for a reasonable transition in any tax law changes so as to not disrupt the current fragile economy.

- To the extent accelerated depreciation is retained, tax normalization must be maintained in the tax law. Tax normalization is a key element in setting utility rates because it lowers a utility's overall cost of capital, which is taken into account in setting its rates and spreads the benefits of accelerated depreciation to customers over the time period that customers are charged for the cost of the related property that gave rise to those tax benefits, allowing for affordable customer rates.

- Any reduction in the corporate tax rate must include continued normalization treatment for any excess deferred taxes created by the reduction. Under such treatment, utilities would continue to transfer the benefits of accelerated depreciation to customers over the time period that customers are charged for the cost of the related property that gave rise to those tax benefits.

- We oppose a higher tax burden on electricity as a way of bridging the budget gap.

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Power by Association℠

Edison Electric Institute

Richard F. McMahon, Jr.
Vice President

August 5, 2013

Thomas A. Barthold
Chief of Staff
The Joint Committee on Taxation
1625 Longworth House Office Building
Washington, D.C. 20515

Dear Mr. Barthold:

Thank you for meeting with us on June 17, 2013, to discuss the importance to U.S. shareholder-owned electric utilities of the House Ways and Means Committee Discussion Draft to reform the taxation of financial products. The purpose of this letter is to provide you and your staff with a response to some questions you raised at our meeting and also clarify some points that the industry has developed following our meeting.

Background

Wholesale natural gas and electricity historically have been among the most volatile commodities. In July of 2008, Henry Hub prices for natural gas rose to $13.32, a 150% rise from $5.27 in May of 2007, followed by a sharp drop of 85% to $1.88 in September of 2009. In August of 2006, the PJM Western Hub prices for wholesale power rose by more than 330% to $230.44 from $53.49 in May of 2006, before settling back to an average price of $48.68 in September of 2006.

To effectively manage such commodity price volatility, U.S. shareholder-owned electric utilities adhere to established comprehensive risk management policies to help ensure an adequate and reliable source of electricity to all consumers at a reasonable cost. Electric utilities consistently disclose in their SEC filings adopted management practices and the contracts executed to mitigate the risks associated with market fluctuations in wholesale power, natural gas, and other commodity prices.

Accordingly, we strongly encourage the modification of the Discussion Draft to address two primary concerns that are critically important to shareholder-owned electric utilities: (1) the treatment of ordinary business transactions consistent with the normal accrual method of accounting under which items of income and deduction are recognized as ordinary items of income and deduction when they are realized, and

(2) appropriate exceptions to the requirement that derivatives be marked-to-market when they are used to manage risk as hedging transactions.

Ordinary Business Transactions

The physical characteristics of electricity are unlike any other marketable commodity because electricity cannot be stored at a reasonable cost. Thus, generation and transmission of electricity must be instantaneous: a grid operator must constantly balance production and demand since a surplus of production over demand for even a fraction of a second can overload lines or a deficit can produce instability. In either instance, a surplus or deficit can cause blackouts to entire regions. Further, unlike other commodities such as water or gas, electricity cannot easily be confined to a subset of the grid; rather, it flows over all interconnected lines in accordance with paths of least resistance.

These unique features of electricity introduce the need for constant balancing and reserve resources. Accordingly, industry members commonly enter into contracts in the ordinary course of business to help avoid power outages and mitigate electric price volatility. Such transactions include power purchase and sale agreements, fuel supply contracts, capacity contracts, tolling agreements, and contracts for ancillary services. Please refer to Exhibit A for contracts commonly used in the ordinary course of business.

Under the Discussion Draft's definition of a derivative in Section 486(a)(1), these standard electric industry contracts could be viewed as "evidence of an interest in" an actively traded commodity (e.g., electricity). Consequently, these contracts could be subject to a mandatory mark-to-market regime requiring the fair market value of these deemed financial derivative instruments to be determined on each relevant date. This would result in the mismatch of costs and revenues, as well as unnecessary volatility. For example, assume in the month of November an electric utility that reports its income on the basis of a calendar year enters into a simple fuel supply agreement for the purchase of coal at a fixed price over the next year. If the price of coal is expected to be higher for the balance of the contract period at year end, mark-to-market treatment would require the utility to report the anticipated benefit from the contract in the current year instead of reporting the actual income from the sale of the electricity produced from the coal in the following year. This would produce higher taxes in the first year from a benefit that was not realized in the first year, and lower taxes in the second year when the benefit of the contract may be realized if prices perform as expected at the prior year-end. Thus, the mark-to-market system introduces volatility in tax costs, which are a cost of service passed on to customers, as a result of a transaction in which the utility sought to manage fuel cost volatility by entering into a fixed-price long-term contract.

Capturing these ordinary course of business electric industry contracts under the broad definition of a "derivative" would introduce unnecessary volatility into customer rates, and contradict the principles of the risk management policies either established by prudent practices of utility management or mandated by state public utility commissions to provide reliability and predictability. Mark-to-market accounting for these contracts would result in a mismatch in the timing of taxable income recognition between revenues from the sale of electricity and the corresponding tax deduction for the cost of purchasing or generating that electricity.

Our industry's proposal, described below, would provide an exception to the mandatory mark-to-market regime for contracts entered into in the ordinary course of business to generate, transmit, distribute, and service electricity to customers through the combination of an explicit exception in the definition of "derivative" for ordinary business transactions and a robust exception for the hedging transactions.

Hedging Transactions

In 2012, the United States produced about four trillion kilowatt hours of electricity generated predominantly through 37% coal, 30% natural gas, 19% nuclear, 12% renewable resources and 2% from petroleum and other gases.[1] The U.S. shareholder-owned utilities attempt to mitigate price risks through risk management programs and policies and through the use of derivative financial instruments primarily in the form of forward contracts, futures contracts, options contracts, financial swap contracts, and financial transmission rights (FTRs).[2] Please refer to Exhibit A for common hedge transactions associated with commodity exposure for electric utilities.

We are pleased that the Discussion Draft provides for the continuation of the exception for hedging transactions as defined in Section 1221(b) and repeals rules for determining capital gains and losses under Section 1234B, 1236, and 1256, resulting in ordinary income and loss from derivatives. We urge the modernization of the taxation of derivatives with common risk management practices adopted by large corporate taxpayers and explicitly address the following in the tax code and regulations:

1. To retain the exception of derivative instruments for hedging transactions as defined under Section 1221(b) as not subject to mark-to-market;
2. To retain the characterization of the gain or loss generated from the settlement of a hedge transaction as ordinary income or loss; and
3. To replace the contemporaneous hedge identification rule for each and every trade confirmation with a rule that recognizes a taxpayer's risk management policy as a means of identifying hedge transactions.

Electric utilities deploy common risk management programs using financial instruments to manage exposure to risks including volatility in interest rates, commodity prices, and currency fluctuations in connection with the purchase and sale of fuels, power, and transmission. We urge the retention of the derivative exception for hedging transactions, the repeal of the capital characterization, and liberalization of the administratively burdensome identification rules to accommodate risk management policies.

Conclusion

As you proceed with your consideration of the reform of the taxation of financial products, we hope you will consider these comments, which are critical to the electric utility industry's ability to deliver an adequate and reliable source of electricity to all

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[1] U.S. Energy Information Administration

[2] Similar contracts are alternatively called transmission congestion contracts (TCCs) or congestion revenue rights (CRRs).

consumers at a stable and reasonable cost. Subjecting our contracts and transactions, which we enter into in the ordinary course of business to stabilize our costs and serve our customers, to a mark-to-market regime would result in significant volatility in customer rates and erode the fundamental principles of adopted risk management practices essential to provide a reliable supply of energy to customers at stable rates.

* * * * * *

The Edison Electric Institute ("EEI") is the association of U.S. shareholder-owned electric utilities, international affiliates, and industry associates worldwide, supporting the electric power industry. The electric power industry is the most capital-intensive industry in the United States—an $840 billion industry representing approximately 3% of real gross domestic product. Our industry is projected to spend approximately $90 billion a year through 2015 for major transmission, distribution, and smart grid upgrades; cyber security measures; new, cleaner generating capacity; and environmental and energy-efficiency improvements

Respectfully submitted,

Richard F. McMahon, Jr.

cc: Mr. Ray Beeman

Dodd-Frank - - Focus Turns to Implementation

Following passage of the Dodd-Frank financial reform bill in July 2010, EEI has been leading a multi-association campaign to preserve the over-the-counter derivatives market for utilities and other end users. EEI's efforts had been focused on ensuring that the Commodity Futures Trading Commission (CFTC) and other regulatory agencies preserve the legislative intent of the law to avoid burdening end users. In July, the CFTC and Securities and Exchange Commission issued a long-awaited final rule to further define the terms "swap" and "security-based swap," among other terms. EEI with the support of its members was able to achieve significant improvements in the final rule from what was initially proposed by the CFTC on the swap rule as well in other key final rules such as the final rules on the end-user exception, swap dealer definition and recordkeeping and reporting.

The focus for EEI members has shifted to implementation and compliance. Going forward EEI will facilitate member discussions as they start to implement the final rules as well as continue to lead coalition efforts on aspects of the final rules that member with which there are still concerns as well as on final rules that are still to be issued. These include final rules on capital margin, and position limits among others. EEI will also be holding its 4th Compliance Forum on October 17-18.

On the legislative front, the CFTC's authorizing statute the Commodity Exchange Act is up for reauthorization this year. EEI's Richard McMahon testified before the House Agriculture Subcommittee on General Farm Commodities and Risk Management in July and advocated legislative action on the following items:

- To ensure that **the De Minimis exception level under the swap dealer definition** is maintained at $8 billion and that this level not be changed without regulatory process and stakeholder involvement.
- To ensure that **Margin Requirements** are not imposed on the swap transactions of commercial end-users. – EEI supports a bill that passed the House of Representatives and has been introduced in the Senate.
- To ensure that the ***Bona Fide* Hedging exemption** is not narrowed or limited, as was done in the recently overturned CFTC final rule on position limits.
- To ensure that the **Financial Entities Definition** excluded commercial end-users. – EEI is proposing a legislative change to address this issue.
- To ensure that **Inter-Affiliate Swap Transactions** aren't subject to reporting and other requirements- EEI supports a bill that passed the House of Representatives and has been introduced in the Senate.

EEI Board Lead:
William Spence, Chairman, President & CEO, PPL Corporation

EEI Board of Directors Meeting
September 2013, Colorado Springs, Colorado

DODD-FRANK SCORECARD

The Commodity Futures Trading Commission (CFTC) has issued more than 80 proposed rules in its work to implement the Dodd-Frank Wall Street Reform and Consumer Protection Act. In response, EEI has filed approximately 60 comment letters with the Commission and other financial regulators and has reinforced members' positions through in-person advocacy meetings, coalition building and earned media.

EEI and its members identified the following Dodd-Frank rulemaking areas as being among the most significant for derivatives end users like electric utilities and other energy companies. As seen below, EEI members achieved major progress in the final CFTC rules from the rules as initially proposed by the CFTC. EEI continues to work with its members to resolve substantive and implementation issues with final and pending rules.

Rule	**Final Rule Contained Changes Advocated by EEI**
Reporting of Pre- and Post-Enactment Swaps	Reduced recordkeeping requirements
Prohibition of Market Manipulation	Rule unchanged from Proposed; received a requested clarification
Whistleblower Provisions	Rule unchanged from Proposed; received requested guidance
Position Limits	Rule vacated and remanded by District Court; EEI filed amicus brief in court of appeals
Real-Time Reporting	Reduced requirements from proposed
Swap Data Recordkeeping and Reporting	Reduced requirements from proposed; phased in reporting
Commodity Options	CFTC reversed decision to do away with Commodity Options; Received requested reporting change through Staff No Action Letter
End-User Exception to Mandatory Clearing	Transactional approach not required
Entity Definitions ("Swap Dealer" and "Major Swap Participant")	De minimis limit raised to $8 Billion
Product Definitions ("Swap")	Forward Contract Exemption codified, Clarify that intent determined at time of contract execution
Margin Requirements for Uncleared Swaps for Swap Dealers and Major Swap Participants	Final Rule pending; key exclusion for end users achieved in the Proposed Rule
Exemptive Order for RTO/ISO Transactions	Final Order exempts key transactions including Financial Transmission Rights

Statement of Richard McMahon
On behalf of the Edison Electric Institute
On "The Future of the CFTC: End-User Perspectives"

Before the Subcommittee on General Farm Commodities and Risk Management
Committee on Agriculture
U.S. House of Representatives

Wednesday, July 24, 2013

Introduction

Chairman Conaway, Ranking Member Scott and Members of the Subcommittee, thank you for the opportunity to discuss the perspective of end-users on the future of the Commodity Futures Trading Commission (CFTC).

I am Richard McMahon, Vice President of Energy Supply and Finance for the Edison Electric Institute (EEI). EEI is the trade association of U.S. shareholder-owned electric utilities, with international affiliates and industry associates worldwide. EEI's U.S. members serve virtually all of the ultimate electricity customers in the shareholder-owned segment of the industry, and represent approximately 70 percent of the total U.S. electric power industry.

The electric power industry is the most capital-intensive industry in the United States—an $840 billion industry representing approximately three percent of real gross domestic product. Our industry is projected to spend approximately $90 billion a year through 2015 for major transmission, distribution and smart grid upgrades; cybersecurity measures; new, cleaner generating capacity; and environmental and energy-efficiency improvements.

My views are shared by the Electric Power Supply Association (EPSA), which is the national trade association for competitive wholesale electricity suppliers, including power generators and marketers. EPSA members include both independent power producers and the wholesale supply businesses of utility holding companies. EPSA members supply electricity nationwide with an emphasis on the two-thirds of the country located within a regional transmission organization or independent system operator (so-called "organized markets"). EPSA members and other competitive suppliers account for 40 percent of the installed electric generating capacity in the United States. These suppliers are the primary sources of electricity for most of Maine to Virginia, across to Illinois, and in Texas and California.

Our members are non-financial entities that primarily participate in the physical commodity market and rely on swaps and futures contracts primarily to hedge and mitigate their commercial risk. The goal of our member companies is to provide their customers with reliable electric service at affordable and stable rates, which has a direct and significant impact on

literally every area of the U.S. economy. Since wholesale electricity and natural gas historically have been two of the most volatile commodity groups, our member companies place a strong emphasis on managing the price volatility inherent in these wholesale commodity markets to the benefit of their customers. The derivatives market has proven to be an extremely effective tool in insulating our customers from this risk and price volatility. In sum, our members are the quintessential commercial end-users of swaps.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (the "Dodd-Frank Act") provides certain exemptions for non-financial end-users, recognizing that they are not the entities posing systemic risk to the financial system. Since passage of the Dodd-Frank Act, we have been actively working with the federal agencies, including the CFTC, as they work their way through the implementation process to ensure that the congressional intent of exempting non-financial end-users remains intact. Even though a majority of the rules have been promulgated by these agencies, concerns still surround some of the remaining issues important to electric companies.

Our members support the Dodd-Frank Act's primary goals of protecting the financial system against systemic risk and increasing transparency in derivatives markets. We believe, however, that there are areas where Congress should consider minor adjustments to ensure the Dodd-Frank Act achieves its purpose while not inadvertently impeding end-users' ability to hedge. As Congress examines possible modifications to the Commodity Exchange Act, we ask that you consider the following issues:

De Minimis Level

A new category of market participants, swap dealers, was created by the Dodd-Frank Act. These swap dealers must register with the CFTC and are subject to extensive recordkeeping, reporting, business conduct standards, clearing, and—in the future—regulatory capital and margin requirements. However, the Act directed the CFTC to exempt from designation as a swap dealer entities that engage in a de minimis quantity of swap dealing. The CFTC issued a proposed rule on the de minimis threshold for comment in early 2011. After review of hundreds of comments, a series of congressional hearings and after dozens of meetings with market participants, the CFTC set this de minimis threshold at $8 billion. However, it will then be reduced automatically to $3 billion in 2018 absent CFTC action.

We oppose such a dramatic reduction in the de minimis threshold without deliberate CFTC action. Inaction is always easier than action, and inaction should not be the default justification for such a major regulatory action. In addition, we believe the CFTC should not have the authority to change the de minimis level without a formal rulemaking process that allows stakeholders to provide input on what the appropriate threshold should be.

Absent these procedural changes, we are concerned a deep reduction in the de minimis level could result in commercial end-users being misclassified as swap dealers, hindering end-users' ability to hedge market risk while imposing unnecessary costs that eventually will be borne by consumers.

Margin Requirements

As I previously mentioned, the electric power industry is one of the most capital-intensive industries in the United States. With our industry projected to spend approximately $90 billion a year through 2015 for major upgrades to the electric system, requiring non-financial end-users to post margin could tie up much-needed capital that otherwise would be used to invest in local economies. With the lack of clarity on whether or not Prudential Regulators and possibly the CFTC plan on requiring non-financial end-users to post margin, Congress should clarify that it did not intend for margin requirements to apply to non-financial end-users.

In addition, we ask Congress to clarify that it did not intend for the CFTC and Prudential Regulators to place limitations on the forms of collateral swap dealers and major swap participants can accept from non-financial end-users if they agree to collateralize a swap as a commercial matter. We support bipartisan legislation that seeks to further clarify that end-users are exempt from margin requirements. H.R. 634, sponsored by Rep. Michael Grimm (R-NY), passed the House on an overwhelmingly bipartisan vote of 411-12. Similar legislation has also been introduced in the Senate—S. 888, sponsored by Sen. Mike Johanns (R-NE).

***Bona fide* Hedging**

On September 28, 2012, the U.S. District Court for the District of Columbia vacated final CFTC rules regarding position limits. These vacated rules defined the term *bona fide* hedging. As written in the CFTC's rule that was vacated, the definition was unnecessarily narrow and would have discouraged a significant amount of important and beneficial risk management activity. Specifically, the rule narrowed the existing definition considerably by providing that a transaction or position that would otherwise qualify as a *bona fide* hedge also must fall within one of eight categories of enumerated hedging transactions, a definitional change neither supported in nor required by the Dodd-Frank Act. This restrictive definition of *bona fide* hedging transactions could disrupt the commodity markets, make hedging more difficult and costly, and may increase systemic risk by encouraging end-users to leave a relatively large portion of their portfolios un-hedged.

Financial Entities

The Dodd-Frank Act defines the term "financial entity", in part, as an entity that is "predominantly engaged in activities that are in the business of banking, or in activities that are

financial in nature, as defined in section 4(k) of the Bank Holding Company Act of 1956." Incorporating banking concepts into a definition that also applies to commercial commodity market participants has had unintended consequences.

Unlike our members, banks and bank holding companies generally cannot take or make delivery of physical commodities. However, banks and bank holding companies can invest and trade in certain commodity derivatives. As a result, the definition of "financial in nature" includes investing and trading in futures and swaps as well as other physical transactions that are settled by instantaneous transfer of title of the physical commodity. An entity that falls under the definition of a "financial entity" is generally not entitled to the end-user exemption—an exemption that Congress included to benefit commercial commodity market participants—and can therefore be subject to many of the requirements placed upon swap dealers and major swap participants. In addition, the CFTC has used financial entity as a material term in numerous rules, no-action relief, and guidance, including, most recently, its cross-border guidance. The Dodd-Frank Act allows affiliates or subsidiaries of an end-user to rely on the end-user exception when entering into the swap on behalf of the end-user. However, swaps entered into by end-user hedging affiliates who fall under the definition of "financial entity" cannot take advantage of the end-user exemption, despite the fact that the transactions are entered into on behalf of the end-user.

Many energy companies structure their businesses so that a single legal entity within the corporate family acts as a central hedging, trading and marketing entity – allowing companies to centralize functions such as credit and risk management. However, when the banking law definitions are applied in this context, these types of central entities may be viewed as engaging in activity that is "financial in nature," even with respect to physical transactions. Hence, some energy companies may be precluded from electing the end-user clearing exception for swaps used to hedge their commercial risks and be subject to additional regulations applicable to financial entities. Importantly, two similar energy companies may be treated differently if, for example, one entity uses a central affiliate to conduct these activities and another conducts the same activity in an entity that also owns physical assets or that has subsidiaries that own physical assets. Accordingly, Congress should amend the definition of "financial entity" to ensure that commercial end-users are not inadvertently regulated as "financial entities."

Inter-affiliate Transactions

Currently, the CFTC's rules and proposed rules generally treat inter-affiliate swaps like any other swap. Hence, companies must, under certain circumstances, report swaps between majority-owned affiliates and must submit such swaps to central clearing unless the end-user hedging exception applies or complex criteria for the inter-affiliate clearing exemption are met. In the absence of a more expansive clearing exemption for inter-affiliate trades, the costs of

clearing likely would deter most market participants from entering into inter-affiliate transactions and could create more risk for clearinghouses. For example, without an exemption, additional affiliates in a corporate family would need to become clearing members or open accounts with a Futures Commission Merchant, and all affiliates would need to develop and implement redundant risk management procedures and trade processing services, such as e-confirm.

The CFTC has provided some relief in the form of no-action letters. However, in many circumstances, these no-action letters do not provide adequate relief and frequently cause more confusion and uncertainty among end-users. EEI supports bipartisan legislation to clarify the requirements placed on inter-affiliate transactions. The Inter-Affiliate Swap Clarification Act (H.R. 677), which seeks to clarify a number of these requirements, has been introduced by Rep. Steve Stivers (R-OH) in the House.

Finally, for the reasons enumerated in the testimony of the American Gas Association, we agree that options and forward contracts that are intended to be physically settled or contain volumetric optionality should be excluded from the definition of a swap.

Conclusion

Thank you for your leadership and ongoing interest in the issues surrounding implementation of the Dodd-Frank Act and their impact on commercial end-users. We appreciate your role in helping to ensure that electric utilities and energy suppliers can continue to use over-the-counter derivatives in a cost-effective manner to help protect our electricity consumers from volatile wholesale energy commodity prices.

Again, I appreciate the opportunity to testify and would be happy to answer any questions.

Edison Electric Institute
Power by Association

FINANCIAL ENTITY DEFINITION - LEGISLATIVE PROPOSAL

Background:

Many energy companies structure their businesses so that a single legal entity within the corporate family acts as a central hedging, trading and marketing entity – allowing companies to centralize functions such as credit and risk management. However, when the banking law definitions are applied in this context, these types of central entities may be viewed as engaging in activity that is "financial in nature." Unlike EEI's members, banks and bank holding companies generally cannot take or make delivery of physical commodities. However, banks and bank holding companies have the ability to invest and trade in certain commodity derivatives. As a result, the definition of "financial in nature" – as defined in section 4(k) of the Bank Holding Company Act of 1956 - includes investing and trading in futures and swaps as well as other derivative transactions that are settled by instantaneous transfer of title of the physical commodity. Unlike banks and bank holding companies, energy companies are in the business of taking and making delivery of commodities.
Provisions available to end users under Title VII of the Dodd-Frank Act are not available to financial entities. As a result, there are a number of negative consequences for the energy industry that would result from the proposed changes to the definition of "financial entity" including:

- The inability to use the end-user exception to mandatory clearing under CEA section 2(h)(7) and 17 CFR part 39 as it is not available to financial entities;
- Potential additional requirements for cash margins for uncleared swaps under proposed 17 CFR Part 23 and 12 CFR part 237; and
- The ability to transact with counterparties that are "utility special entities" under guidance recently issued by the Commodity Futures Trading Commission.

The end result would be to impose significant new regulatory burdens and cost burdens on end users that are contrary to congressional intent.

Current Statuary Language:

The definition of financial entity includes, in CEA Section 2(h)(7)(C)(i)(VIII), "a person predominantly engaged in activities that are in the business of banking, or in activities that are financial in nature, as defined in section 4(k) of the Bank Holding Company Act of 1956."

CEA Section 2(h)(7)(C)(iii), titled LIMITATION, provides that: "Such definition shall not include an entity whose primary business is providing financing, and uses derivatives for the purpose of hedging underlying commercial risks related to interest rate and foreign currency exposures, 90 percent or more of which arise from financing that facilitates the purchase or lease of products, 90 percent or more of which are manufactured by the parent company or another subsidiary of the parent company."

Proposed Statutory Changes:

Option One:

Insert the following phrase in Section 2(h)(7)(C)(i)(VIII) after “1956”:

“but excluding any person that is a commercial market participant as defined by the Commission and is neither included in subclauses (I)-(VII) hereof nor supervised by a ‘prudential regulator’ as defined in section 1a(39) of this Act.”

Option Two:

Amend Section 2(h)(7)(C)(iii) by inserting “(I)” after “entity”, and inserting after “company” at the end of the subclause “, or (II) is a commercial market participant as defined by the Commission that is neither included in subclauses (I)-(VII) of clause (i) in subparagraph (C) nor supervised by a ‘prudential regulator’ as defined in section 1a(39) of the CEA.”

**NOTE - Commercial market participant as explained by the Commission in the preamble to its Final Rule on the definition of Swap essentially means an entity who regularly makes or takes delivery of the referenced commodity in the ordinary course of business as a producer, user or merchant of the commodity.

MARK ZANDI BIOGRAPHY

EEI Fall Board and Chief Executives Meeting, September 2013

Mark M. Zandi is chief economist of Moody's Analytics, where he directs economic research. Moody's Analytics, a subsidiary of Moody's Corp., is a leading provider of economic research, data and analytical tools. Zandi is a cofounder of Economy.com, which Moody's purchased in 2005.

Zandi's broad research interests encompass macroeconomics, financial markets and public policy. His recent research has focused on mortgage finance reform and the determinants of mortgage foreclosure and personal bankruptcy. He has analyzed the economic impact of various tax and government spending policies and assessed the appropriate monetary policy response to bubbles in asset markets.

A trusted adviser to policymakers and an influential source of economic analysis for businesses, journalists and the public, Zandi frequently testifies before Congress on topics including the economic outlook, the nation's daunting fiscal challenges, the merits of fiscal stimulus, financial regulatory reform and foreclosure mitigation.

Zandi conducts regular briefings on the economy for corporate boards, trade associations and policymakers at all levels. He is on the board of directors of MGIC, the nation's largest private mortgage insurance company, and The Reinvestment Fund, a large CDFI that makes investments in disadvantaged neighborhoods. He is often quoted in national and global publications and interviewed by major news media outlets, and is a frequent guest on CNBC, NPR, *Meet the Press*, CNN and various other national networks and news programs.

Zandi is the author of *Paying the Price: Ending the Great Recession and Beginning a New American Century*, which provides an assessment of the monetary and fiscal policy response to the Great Recession. His other book, *Financial Shock: A 360º Look at the Subprime Mortgage Implosion, and How to Avoid the Next Financial Crisis,* is described by the New York Times as the "clearest guide" to the financial crisis.

Zandi earned his B.S. from the Wharton School at the University of Pennsylvania and his PhD at the University of Pennsylvania. He lives with his wife and three children in the suburbs of Philadelphia.

National Response Event

EEI Fall Board and Chief Executives Meeting, September 2013

It has been nearly one year since Superstorm Sandy made landfall. Sandy's aftermath, though challenging, drove a new spirit of collaboration among electric utilities and with the federal government and led to a redoubling of efforts toward continual improvement in the areas of mutual assistance and storm restoration. This session will focus on the industry's enhanced mutual assistance program; the growing industry and government partnership; and the communications and outreach strategy developed to help us tell our story.

Enhanced Mutual Assistance

American Electric Power President and CEO Nick Akins, chair of the EEI Restoration/Mutual Assistance Working Group, will provide an update and lead a discussion of the industry's enhanced mutual assistance program, which consists of an industry-wide national response event (NRE) framework that has been designed, implemented, and exercised to respond to widespread power outages that impact a significant population or several regions across the U.S. and require restoration resources from multiple regions. This industry-wide NRE process is but one component of the industry's overall improvements to the mutual assistance program. Other areas include:

- situational awareness on the needs to restore power safely and as quickly as possible;
- the consolidation of the Mid-Atlantic, New York, and Northeast regional mutual assistance groups (RMAGs); and
- engaging utility contractors and public power.

Industry and Government Partnership

The electric power industry assembled an unprecedented national response to help restore service to the millions of customers who lost power in the wake of Superstorm Sandy. Because of the severity of this storm, industry and government officials worked together to remove barriers and to cut through red tape that arose during the response and restoration process. The result of these partnerships is now a higher level of collaboration between the electric power industry and government to ensure we are all better prepared for the next major national outage event.

EEI Executive Vice President, David Owens, will provide an update on the industry's continued efforts to work closely with the federal government and the states to enhance and formalize the partnerships that strengthen the industry's response and restoration process.

Communications and Outreach Strategy

Mutual assistance is the cornerstone of electric utility operations during emergencies and sets the industry apart from others—when disaster strikes we voluntarily band together to restore service to our customers. The industry has a compelling story to tell and communicate to its stakeholders about our mutual assistance program and the enhancements made and partnerships developed over the past 10 months.

EEI Senior Vice President, Brian Wolff, will provide the board an update on the industry's communications and outreach strategy focused on enhance mutual assistance. The strategy

focuses on educating and informing both industry and external stakeholders about the new NRE process and other enhancements to the electric power industry's response and restoration initiatives.

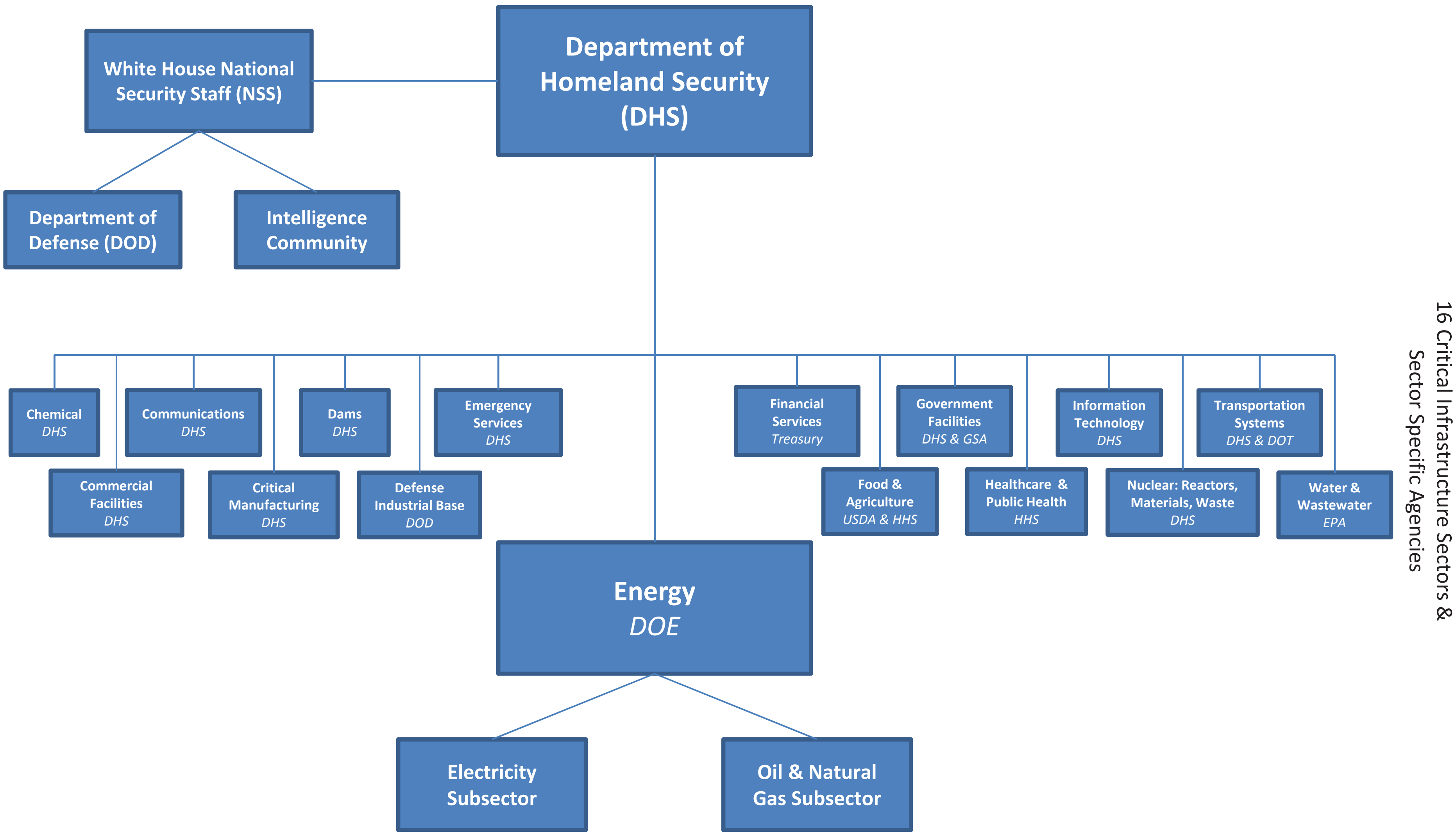
CYBER SECURITY

There has been a lot of activity related to cyber security preparedness and public policy. Following President Obama's Executive Order, the National Institute of Standards and Technology (NIST) is developing a "framework" for critical infrastructure protection that includes input from all critical sectors. The electric sector has been particularly active to ensure that any new framework builds on our existing regulatory structure, including the mandatory and enforceable cyber security standards the industry already allows.

In addition to regulatory and policy issues, the industry has entered into an active and valuable partnership at the senior executive level. The Electricity Subsector Coordinating Council (ESCC) recently was reconstituted to include CEOs and trade association heads from across the segments of the industry. This partnership has resulted in closer coordination around incident response, improved information sharing and access to classified information, and a commitment to deploy proprietary government tools and technologies to better monitor and protect electric utility systems.

Government-Industry Coordination

Organizational Chart (Discussion Draft)



Government-Industry Coordination

Organizational Chart (Discussion Draft)

Electricity Subsector Coordinating Council (ESCC)

30 member body to serve as the principal entity coordinating with government counterparts on planning, preparedness, resilience, and recovery issues related to national security issues affecting the electric grid.

Leadership – 1 Chair, 2 Vice Chairs (3)

Steering Committee – NIAC representative, APPA, CEA, EEI, EPSA, ISO/RTO Council, NEI, NERC, and NRECA (9)

Asset Owners – CEOs proportionally representing asset owners from across industry segments (18)

Electricity Subsector Information Sharing and Analysis Center (ES-ISAC)

Day-to-day operations run by NERC

Electricity Sub-Sector Coordinating Council Charter

Purpose and Scope

The purpose of the Electricity Sub-Sector Coordinating Council (ESCC) is to facilitate and support the coordination of sub-sector wide, policy-related activities and initiatives designed to improve the reliability and resilience of the electricity sub-sector, including physical and cyber security infrastructure and emergency preparedness of the nation's electricity sub-sector. The ESCC will establish a dialogue between senior industry representatives and Administration officials in order to carry out the role of the Sector Coordinating Council as established in the National Infrastructure Protection Plan (NIPP) for the electricity sub-sector.

The mission of the ESCC is based on the National Infrastructure Advisory Council (NIAC) recommendation to initiate an executive-level dialogue with electric power sector chief executive officers (CEOs) and other senior executives on the roles and responsibilities of the industry in addressing high impact infrastructure risks and potential threats, and is consistent with Presidential Policy Directive 21, Critical Infrastructure Security and Resiliency, and Executive Order 13636, Improving Critical Infrastructure Cybersecurity. The ESCC is self-governed, and participation by its constituencies is voluntary. The ESCC is not regulated by any federal agency.

The ESCC will serve as the principal liaison with the Government Coordinating Council (GCC) for energy and its member federal agencies, including the Department of Energy (DOE), which serves as the Sector Specific Agency for the electricity sub-sector, and federal utilities, on issues pertaining to joint planning, preparedness, resilience, and recovery related to events of national significance that may affect the secure and resilient supply and delivery of electricity.

Primary Objectives

Aligned with the energy sector vision and goals, as established in the NIPP for the electricity sub-sector, the primary objectives of the ESCC are to:

(1) Coordinate with the GCC and federal agencies and other Sector Coordinating Councils;
(2) Work with the federal government to improve the flow of information and access to classified information;
(3) Facilitate identification and sharing of tools and technologies to improve electricity sub-sector security and resilience; and
(4) Collaborate with the federal government on coordinated government-industry preparedness and response planning for events of national significance.

To carry out these objectives, the ESCC will:

- Communicate ESCC activities, information, and developments effectively, and in a timely manner, to the entire electricity sub-sector, consistent with national security considerations.

- Encourage the federal government to declassify and broadly disseminate threat information, as appropriate.

- Promote sharing of information between the federal government and the electricity sub-sector about physical and cyber threats, vulnerabilities, incidents, and potential protective measures affecting sub-sector members.

- Work with the federal government to facilitate the deployment of government tools and technologies related to the purposes described in this charter.

- Work with the federal government to improve access to timely and actionable information by appropriate recipients of such information.

- Identify priorities and risks on an ongoing basis to inform the efforts of both the government and the sector.

- Provide advice and recommendations to the North American Electric Reliability Corporation (NERC) on the roles, activities and capabilities of the Electricity Sector Information Sharing and Analysis Center (ES-ISAC).

- Participate in efforts related to the development, implementation, update and revision of the Energy Sector Specific Plan and review of the Energy Sector Annual Report.

- Collaborate with the federal government on relevant research and development efforts.

- Advise the federal government about the risks, benefits, and potential implications of policies and events on the electricity sub-sector.

Membership and Governance Structure

The ESCC consists of CEO level representatives of the asset owners and operators of the North American electricity industry, including:

- generation, transmission and distribution assets, from all ownership categories;
- regional transmission organizations and independent system operators (ISOs/RTOs), represented by a designee of the ISO/RTO Council (IRC);
- NERC, which is the Electric Reliability Organization certified by the Federal Energy Regulatory Commission under Section 215 of the Federal Power Act;
- the National Infrastructure Advisory Council (NIAC); and
- the Canadian Electricity Association (CEA), in view of the interconnected nature of the North American electric grid.

It is expected that federal utilities also will participate in the activities of the ESCC.

Officers: The ESCC shall be led by a Chair and two Vice Chairs.

The Chair and the Vice Chairs shall be members of each of the asset owner classes represented by APPA, EEI, and NRECA, as designated by the trade association CEOs. They shall rely upon the staffs of these Associations and NERC to support the activities of the ESCC. The office of Chair shall rotate among the three asset owner classes. Terms for Chair and Vice Chairs shall be for two years commencing on January 1 of the year following designation as an officer.

The Chair, if present, shall preside over all meetings of the members. A Vice Chair shall act as Chair in the absence of the Chair.

Membership: The ESCC shall have 30 members composed of:

- The Chair and Vice Chairs (3 members)
- The members of the Steering Committee (9 members)
- Eighteen additional CEO-level executives drawn from the memberships of the asset owner classes represented by APPA (3 members), EEI (12 members), and NRECA (3 members), respectively. The CEOs of these trade associations shall be responsible for the appointment of the CEO-level executives designated to represent their respective memberships.

There are no limits on the term that a member of the ESCC may serve. In the case of a vacancy on the ESCC of a member other than a Steering Committee representative, the CEO of the member trade association representing the asset owner class for the vacant seat shall appoint a new member to fill the vacancy. Possession of a security clearance is not a condition of membership on the ESCC.

The ESCC will function as a body representing the views of the owners and operators of the nation's electricity infrastructure. To the extent views among members vary, members may express divergent concerns and perspectives.

ESCC Steering Committee: The Steering Committee shall be composed of a CEO-level representative from each of the following:

- American Public Power Association (APPA)
- Canadian Electricity Association (CEA); the CEO of CEA may designate an alternate, who shall be the CEO of a CEA member organization. (The alternate may attend any ESCC meeting with the CEO of CEA, or in place of the CEO of CEA.)
- Edison Electric Institute (EEI)
- Electric Power Supply Association (EPSA)
- ISO/RTO Council (IRC)
- National Rural Electric Cooperative Association (NRECA)
- North American Electric Reliability Corporation (NERC)
- Nuclear Energy Institute (NEI)
- National Infrastructure Advisory Council (NIAC).

A Secretary shall perform administrative functions as directed by the Steering Committee, including scheduling of meetings or conference calls as required to conduct the business of the ESCC and as requested by the government; preparation and distribution of meeting notices, agendas, and minutes; and the maintenance of ESCC records. The Secretary may coordinate with relevant entities as necessary to perform these functions, including but not limited to coordination with the ES-ISAC to support the Secretary's responsibilities associated with communication and dissemination of information to appropriate entities such as the ESCC, or to the electricity sub-sector as a whole.

The Steering Committee shall have the following duties:

- Provide policy direction for the operation of the ESCC,
- Form committees and working groups populated by ESCC members, their employees, and other electricity sub-sector representatives consistent with the ESCC's direction.

- Communicate with the electricity sub-sector beyond the ESCC members with regard to the activities of the ESCC, consistent with national security,
- Appoint a Secretary to conduct the duties of an administrative nature, as specified above,
- Ensure the effective and timely communication of relevant activities, information and developments of the ESCC to the electricity sub-sector, consistent with national security using communications tools and mechanisms including those available through or facilitated by the ES-ISAC and Steering Committee members,
- Provide a process for inclusion of staff and guests as appropriate, and
- Provide such other assistance to the ESCC as may be appropriate.

Meetings

The ESCC will meet at least once a year. ESCC meetings will be noticed to members in writing (electronic transmittal is acceptable) ten (10) or more business days in advance if possible.

Any decisions made by the ESCC with regard to a particular issue shall be made during a duly constituted meeting.

Approval

The Steering Committee of the Electricity Sub-Sector Coordinating Council, as established by the electricity sub-sector and recognized by the Department of Energy, approves this charter.

This document may be amended upon two-thirds majority vote of the Steering Committee members.

Approved on August 5, 2013

Transmission ROE

Greg Abel, Chairman, President and CEO of MidAmerican Energy Holdings, Inc., and Pat Vincent-Collawn, Chairman, President and CEO of PNM Resources, Inc., and co-chairs of the CEO Policy Committee - Energy Delivery, will provide an update on recent outreach on transmission return on equity (ROE) with the Federal Energy Regulatory Commission and media outreach, in conjunction with EEI's Transmission Investment White Paper. These outreach efforts were made to highlight transmission development needs and advocate for consistency between FERC's rate methodologies and its policy goals for infrastructure development.

At prior CEO meetings, EEI has garnered support for, and implemented a strong advocacy message on the need for stable and adequate ROE for transmission investment given its many challenges and benefits. In addition, EEI has developed advocacy materials, including talking points, emphasizing the value of transmission and defending adequate returns on these investments.

Significance for Members

Adequate ROEs continue to face broad challenges. FERC currently has nine **(9)** pending case-specific complaints, including a recent filing in February, involving several regions, requesting significantly lower ROEs than currently effective. These complaints request that FERC significantly reduce base transmission ROE by 100-200 basis points, to around **9%**. In the *Massachusetts Attorney General-Bangor Hydro, et al.* complaint proceeding, the presiding judge issued his initial decision in early August finding that ROEs of 10.6% for the refund period (under FERC rules) and 9.7% ROE for subsequent application were reasonable, compared to a currently authorized ROE of 11.14%. The judge's decision is subject to review by FERC Commissioners. If FERC affirms the presiding judge's decision, and grants lower returns requested in other complaint proceedings, regulatory certainty will be reduced and investor confidence in adequate, stable returns for long-life transmission investments will be reduced. Members will be challenged to secure financing at reasonable rates, maintain or improve credit ratings, and provide adequate returns for shareholders.

EEI's advocacy is focused on ensuring that returns are sufficient to gain access to needed capital to make transmission infrastructure investments on reasonable terms.

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Power by Association℠

Edison Electric Institute

David K. Owens
Executive Vice President, Business Operations Group

August 14, 2013

Via Hand Delivery

The Honorable Jon Wellinghoff
Chairman
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Subject: **EEI White Paper - Transmission Investment-Adequate Returns and Regulatory Certainty Are Key, June 2013**

Reference: Docket No. RM13-18-000, WIRES Petition for Statement of Policy on Electric Transmission Rates of Return on Equity

Dear Chairman Wellinghoff:

Edison Electric Institute (EEI) requests the opportunity to inform the record in the docket created in response to the WIRES' (the Working group for Investment in Reliable and Economic Electric Systems) petition filed on June 26, 2013. A number of parties filed a joint letter on July 12th, in the referenced docket, responding in large part to EEI's White Paper (White Paper) referenced above. Subsequently, some parties filed individual comments in the same docket. To ensure a complete record, EEI herein tenders its White Paper addressing its concerns with determining transmission investment returns on equity under current economic and financial conditions, briefly summarized below. EEI's White Paper also provides context for the comments filed in this docket.

As discussed in the White Paper, a robust transmission system is critical to electric reliability and provides numerous benefits to customers, as noted in comments submitted by the American Wind Energy Association and Solar Energy Industry Association in this docket. Transmission investment requires significant capital. EEI members have responded to the growing transmission needs of our nation, more than doubling year-over-year transmission investment from $5.5 billion in 2001 to $14.1 billion in 2012. This significant increase was supported by the Commission's policy goals to promote infrastructure development. During this time, the risks of building transmission were not diminished. Those risks remain even with temporarily low interest rates resulting from federal government monetary action.

Under current economic and financial conditions, EEI is extremely concerned that the Commission's preferred discounted cash flow methodology (DCF) produces returns on equity (ROEs) that are insufficient to meet legal and regulatory standards and, moreover, compromise the Commission's established policy goals, as noted in the White Paper. EEI seeks a proper balance between the application of the DCF methodology and the Commission's strategic goals for infrastructure development. EEI is concerned that short-term reactions today to short-term market conditions may negatively impact long-term investments for projects with a useful life of over 40 years. The Commission should maintain flexibility in its analysis and exercise its discretion in determining ROEs that protect customers while also enabling utilities to attract the necessary capital investment. Such flexibility and a longer-term view will help capital flow to needed transmission infrastructure investment while, at the same time, assuring just and reasonable rates.

EEI supports prompt attention by the Commission on the matters raised in the White Paper. I am happy to discuss these matters further.

Respectfully Submitted,

David K. Owens

David K. Owens

cc: James P. Fama, Vice President, Energy Delivery, EEI
Tony V. Ingram, Senior Director- Federal Regulatory Affairs, Energy Delivery, EEI

Attachment

Edison Electric Institute
Power by Association

FERC ISSUES – BASE ROE COMPLAINTS

Docket No.	Utility(ies)	Complainant(s)	Current ROE	Requested ROE	Status
EL11-66 **(9/30/11)**	Bangor Hydro-Electric Central Maine Power National Grid NextEra NSTAR NE Utilities CL&P WMECO Public Service Co. of NH United Illuminating Unitil Vermont Transco	Massachusetts Attorney General, *et al.*	**11.14%**	**9.2%**	ALJ initial decision Aug. 2013 recommending 10.6% during refund period and 9.7% prospectively
EL13-33 **(12/28/12)**		Environmental Northeast Great Boston Real Estate Board National Consumer Law Center NEPOOL Industrial Customer Coalition	**11.14%**	**8.7%**	initial order (and consolidation) pending before FERC
EL12-39 **(2/29/12)**	Florida Power Corporation (d/b/a Progress Energy Florida)	Seminole Electric Cooperative Florida Municipal Power Agency	**10.8%**	**9.02%**	initial order pending before FERC
EL13-63 **(5/13/13)**			**10.8%**	**8.63%**	initial order pending before FERC
EL12-59 **(4/20/12)** **EL13-78** **(7/19/13)**	Southwestern Public Service Co.	Golden Spread Electric Cooperative	**11.27%**	**9.65%**	initial order pending before FERC
EL12-77 **(6/21/12)**	Public Service Co. of Colorado	Grand Valley Rural Power Lines Yampa Valley Electric Assoc. Intermountain Rural Electric Assoc. Tri-State Generation & Trans. Assoc.	**10.25%**	**9.15%**	Order setting matter for settlement proceedings issued Oct. 2012; partial settlement to be filed early Sept. 2013
EL12-84 **(7/13/12)**	Maine Public Service Co.	MPS Customer Group	**10.5%**	**8.83%**	Settlement approved by FERC Aug. 2013 for 9.75%
EL12-101 **(9/11/12)**	Niagara Mohawk Power Corp. (National Grid)	New York Association of Public Power	**11.5%**	**9.49%**	initial order pending before FERC
EL13-16 **(11/02/12)**	Niagara Mohawk Power Corp. (National Grid - NYISO)	Municipal Electric Utilities Association of New York	**11.5%**	**9.25%**	initial order pending before FERC
EL13-48 **(2/27/13)**	Baltimore Gas & Electric Pepco Holdings, Inc. Pepco Delmarva Power & Light Atlantic City Electric	Delaware Div.of the Public Advocate, *et al.*	**11.3%**	**8.7%**	initial order pending before FERC

New PURPA Developments

FERC has moved away from its traditional interpretation of avoided costs under PURPA. PURPA defines avoided cost as "the incremental costs of electric energy, capacity, or both, which, but for the purchase from the QF, such utility would generate itself or purchase from another source." However, in a 2010 order in a case pertaining to California, FERC allowed a state with source specific renewable portfolio standards to set avoided cost rates for separate categories of renewable QFs. This leads to higher prices for renewable QF generation than allowed under the traditional understanding of avoided cost.

In addition, after many years of giving state PUCs broad deference in how they implement PURPA, FERC recently initiated its first court action against a state PUC to enforce FERC's decision that the PUC improperly applied PURPA. While the specific matters at issue largely involved contract issues, FERC's initiative has emboldened many QFs to ask FERC to review PURPA implementation practices in several other states. These actions threaten to undermine state flexibility in applying PURPA. EEI's concern is shared by FERC Commissioner Tony Clark and NARUC.

EEI has been engaged in active outreach and advocacy through varied avenues. EEI has intervened in a proceeding against the Montana PUC where a QF is contesting the use of competitive bidding to determine avoided costs. Our position reaffirms the importance of competitive processes to determine avoided cost. EEI also has been meeting with FERC Commissioners, working with NARUC, state commissioners and other stakeholders to ensure that state PUCs may continue to use their traditional flexibility to determine avoided costs.

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NEW PURPA DEVELOPMENTS

Background: Role of FERC and the States

As you know, although PURPA is a federal law, implementation is left to the state regulatory commissions, which historically have had broad discretion to determine avoided costs pursuant to FERC's regulations. States have generally determined avoided cost either by administratively determining them or through market based methods. In 2005 Congress exempted some larger Qualifying Facilities (QFs) from PURPA where there is adequate competition for generation.

FERC's Reinterpretation of Avoided Costs

Recently, FERC departed from the Commission's traditional interpretation of PURPA's "avoided cost." PURPA defines avoided cost as the cost to the utility of energy which "but for the purchase of electricity from [a QF] such utility would generate or purchase from another source." This is a definition which does not depend on the technology, size or efficiency of the QF, but rather focuses on the cost of alternative generation. In a 2010 order clarifying its PURPA regulations in response to California PUC's request, FERC determined that in estimating avoided costs, states can take account of constraints on utility purchases of energy and capacity created by state requirements to purchase certain amounts of renewable energy. **Thus, FERC allowed states to adjust avoided cost to reflect the fact that state renewable portfolio standards constrain utility supply options (i.e., toward renewable options).**

This means that a state can impose multiple avoided costs, one each for discrete types of renewable technologies if the state has imposed mandates for discrete renewable energy source technologies (e.g., wind, distributed photovoltaic, central station photovoltaic, fuel cells, biomass-derived synthetic fuels). This is true even if the cost of such technologies is above that of other sources of generation. In the current environment, the effect of this kind of avoided cost unbundling is to raise the prices utilities must pay for power under PURPA.

At this time, such tiered rates would only apply where a state has imposed renewable purchase requirements such that, given growth trends and other factors, a utility's next purchase must be from a renewable source.

FERC Has Stepped Up Use of Its Enforcement Authority Over State Commissions

In addition, FERC has recently departed from its historical approach of giving states great deference in implementing PURPA. In a series of cases, FERC has initiated federal court actions to enforce some decisions of the Idaho Commission. FERC Commissioner Clark has strenuously dissented from these decisions and believes that FERC should continue to give broad deference to state commissions. He also stated FERC should discourage parties from seeking FERC review of state decisions.

Other FERC Commissioners have stated that these cases are not intended to set a precedent and relate to some unique contract issues.

However, FERC's exertion of its enforcement authority has empowered the QF community to petition FERC (as PURPA allows) to review many more state commission PURPA decisions. Since FERC must respond to these petitions (and has not acted on most of them), the impact of greater FERC review of state PURPA actions is a new concern. NRECA is very upset with FERC's overturning of a coop's decision to stop purchasing power from a small QF because the QF had refused to pay for its power purchases from the coops. They believe that FERC erroneously handled what essentially was a nonpayment situation.

NARUC's Concerns

Given these recent PURPA developments, NARUC has expressed deep disappointment in FERC's recent enforcement actions and filed protests at FERC in many of the QF proceedings against the states.

NARUC passed a Resolution July which urged FERC to exercise restraint in the enforcement of PURPA. In its resolution NARUC urged FERC, when responding to complaints, to consider (i) whether applicant exhausted available State remedies, (ii) whether applicant allowed existing State appeal/rehearing options to lapse unexercised before seeking FERC enforcement, (iii) the impact of contract and other pertinent State law, and (iv) whether, as part of required Section 210(b)(1) determination, the subject action results in just and reasonable retail rates. NARUC further resolved that FERC should proceed cautiously with any determination or action that overrides State public interest, contract, terms of service and other State policy determinations, and only after careful consideration of the public interest should FERC exercise authority to directly sue state commissions on behalf of an industry stakeholder.

EEI's Intervention in the Montana Proceeding Supports Competitive Processes to Determine Avoided Costs

Given these concerns, EEI recently intervened in a FERC case filed by QFs against the Montana PUC which essentially challenged the use of competitive bidding to determine avoided cost in a situation where renewable portfolio requirements are not an issue. EEI participated at the request of Northwestern Energy and on the side of the state PUC, NARUC and state consumer advocates.

EEI filed the protest out of concern that the petition invites the Commission to unnecessarily interject itself into a state regulatory agency's implementation of PURPA and appears to take the erroneous position that states may not require competitive solicitations to determine avoided cost under FERC regulations and PURPA. EEI reaffirmed the importance of competitive processes in determining avoided costs and reinforced to FERC that the primary responsibility for implementation of PURPA falls to the states. EEI urged FERC to continue its historic policy of giving the states wide latitude in implementing PURPA and in achieving all of PURPA's goals, including just and reasonable rates to consumers. See Appendix for more details.

Implications for Future Developments and EEI Actions Items

FERC's new interpretation of PURPA can affect how many states determine avoided cost. In addition, recent cases have demonstrated that the process of determining avoided costs for intermittent generation facilities is more complex than it has been for base load facilities. Therefore, we believe it is critically important that state commissions fully understand these newer PURPA developments so that they can implement PURPA to achieve all of its goals, including reasonable rates for consumers.

EEI is working with NRRI and NARUC to help educate state commissioners and others on these developments in the following activities:

1. EEI, together with APPA and NRECA, is funding a new NRRI study of PURPA implementation policies and activities. With constant turnover in commissioners, we agree it is important to educate them on the best approaches to achieve all PURPA's goals.
2. At EEI's urging, once the NRRI study is done, NARUC will schedule educational workshops for commissioners and their staffs on these issues. EEI plans to participate, as appropriate.

EEI will continue to actively monitor and intervene as necessary at FERC while continuing to work with the state commissioners, the consumer advocates and other industry stakeholders to ensure that the determination of avoided costs is consistent with all the requirements of PURPA and is just and reasonable and in the best interests of consumers.

APPENDIX: SELECT PURPA PROCEEDINGS AT FERC AGAINST STATE PUBLIC UTILITY COMMISSIONS

Petitions for enforcement have been filed by QFs against at least seven state PUCs including, California, Idaho, Iowa, Minnesota, Montana, Oregon, and Vermont. At the heart of most of these complaints are issues related to avoided costs. Below are summaries of recent disputes over PURPA implementation that involve state commissions.

Montana

Key Issue

QFs have challenged a Montana Public Service Commission's Rule's consistency with FERC's PURPA regulations concerning calculation of avoided cost and whether states may require competitive solicitations to determine avoided cost consistent with the Commission's regulations without violating PURPA.

Summary

On June 17, 2013, Hydrodynamics, Montana Marginal Energy, and WINData petitioned FERC to take enforcement action under Section 210(h) of PURPA, (or in the alternative, issue a declaratory order) finding that the Montana Public Service Commission's (MPSC) Rule A.R.M. § 38.5.1902(5) and MPSC decisions interpreting the MPSC Rule, fail to implement PURPA and FERC's regulations insofar as the MPSC Rule eliminates the rights of QFs to create a legally enforceable obligation (LEO) and to choose how to sell their energy and capacity.

In its petition, Petitioners argue that the MPSC Rule eliminates the QF rights under PURPA to sell to its host utility either on an "as available" basis or pursuant to a LEO "over a specified term." Under the MPSC Rule, a QF with an installed capacity greater than the standard offer threshold cannot create a LEO or sell its energy and capacity over a specified term using forecast avoided cost pricing unless the QF wins a competitive solicitation. Petitioners allege the MPSC's decisions interpreting the MPSC Rule have affirmed the MPSC's position that if a QF larger than the standard offer threshold does not win a competitive solicitation, the QF only has the right to sell its output at an "as available" rate as set forth in 18 C.F.R. § 92.304(d)(2)(i). Petitioners claim the "as available" rate is a short-term rate that does not permit a QF to take advantage of long-term financing as would be the case with forecast avoided cost pricing.

Petitioners asked FERC to find that the MPSC Rule as applied by the MPSC is unfair and discriminatory and that NorthWestern has an obligation to negotiate in good faith with prospective QFs and that a failure to negotiate may result in a LEO. Petitioners also requested that FERC act on or before August 13, 2013.

EEI's Comments: **EEI** has filed a protest in this proceeding, taking the position that the states should have wide latitude in implementing PURPA and that states may require competitive solicitations to determine avoided cost. EEI is very concerned that a ruling in this proceeding which calls into question the use of competitive solicitations could have broad impacts that will undermine a substantial number of States that have made competitive processes a cornerstone of their avoided cost determinations. EEI believes that the power supply industry has become much more competitive since the enactment of PURPA and the QF industry has matured sufficiently that QFs can and should compete on the merits with other supply options.

Current Status

FERC has not yet acted in this proceeding.

Idaho

At least six petitions have been filed against the Idaho Public Utilities Commission (PUC) by developers of wind projects asking FERC to initiate an enforcement action against the Idaho Commission to overturn the Idaho Commission's orders which rejected the power purchase agreements between the developers and the Idaho utilities. FERC has determined to enforce PURPA in Federal district court in the *Murphy Flat, Grouse Creek* and *Rainbow Ranch Wind* proceedings

Key Issue

All of the Idaho disputes essentially stem from the fact that the PUC had determined that the contracts were not eligible for the published avoided cost rates because they weren't y executed by both parties until after the state's PURPA rules had changed even though negotiations had been ongoing over many months earlier.
Summary

FERC explained in its Notice of Intent to Act that the Idaho PUC's basis for rejection of the QF power purchase agreements violated PURPA, which permits a qualifying facility (QF) in some circumstances to obligate a utility to buy its output prior to full execution of a power purchase agreement. FERC stated that under its regulations, a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF and these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations. It further explained that the phrase legally enforceable obligation is broader than simply a contract between an electric utility and a QF and that the phrase is used to prevent an electric utility from avoiding its PURPA obligations by refusing to sign a contract, or delaying the signing of a contract, so that a later and lower avoided cost is applicable. *See* FERC's Notice of Intent to Act (March 15, 2013) (Docket No. EL13-39) (*Grouse Creek Wind Park, LLC).*

FERC recognized that it is up to the States, not the Commission, to determine the specific parameters of individual QF power purchase agreements, including the date at which a legally enforceable obligation is incurred under State law. FERC believes, however, that it within its authority to bring an enforcement action to correct a state's "misreading" of the Commission's PURPA regulations and precedent. FERC believes the enforcement action will address the defects in the PURPA rules adopted by the state commission. *See* FERC's Notice of Intent to Act (March 15, 2013) (Docket No. EL13-39) (*Grouse Creek Wind Park, LLC).*

Current Status

FERC has filed in district court in Idaho to enforce PURPA in the disputes concerning *Grouse Creek* and *Murphy Flat.* FERC has also indicated it will file in district court to enforce PURPA in *Rainbow Ranch Wind.* At this time, FERC has not filed in court.

California

Key Issue

The main issue is whether part of the California Commission's feed-in tariff ("FIT") program, known as the renewable market adjusting tariff, is inconsistent with PURPA.

Summary

On June 13, 2013 Winding Creek Solar (a QF), petitioned FERC to initiate enforcement action against the CPUC to remedy the issuance of a series of CPUC orders implementing amendments to California Public Utilities Code § 399.20, which prescribes a renewable FIT program at market prices for eligible renewable energy generation sources with a generation capacity of 3 MW or less. Winding Creek contends that the FIT (feed-in-tariff) program, (the renewable market adjusting tariff or Re-MAT) is based on CPUC's "incorrect" PURPA interpretation and is contrary to requirements in FERC's regulations and in violation of FPA because:

1. it fixes wholesale price for the purchase of power from a QF at a price that hasn't been determined to be utility's full-long term avoided costs;
2. it creates a rule with respect to rates under PURPA Section 210(f)(1) that eliminates a QF's ability to seek an avoided cost long-run rate pursuant to 18 C.F.R. §292.304(d)(2)(ii) except through the Re-MAT Program.

On August 12, 2013, FERC issued a brief Notice of Intent Not to Act, declining to initiate enforcement. FERC said Petitioners may bring enforcement action against the California Commission in appropriate court. No further explanation was offered.

Current Status

FERC has indicated in its Notice of Intent Not to Act that it will not bring an enforcement action although Winding Creek Solar may do so. FERC did not express an opinion on the merits of Winding Creek Solar's claims

Iowa

Key Issue

The key issue is whether the litigation is simply a dispute about disconnection of a utility customer or a utility's obligations under PURPA to provide service to a QF.

Summary

This proceeding involves a long and contentious history since 1998 between the Sweckers, a retail customer of Midland Power Cooperative who bought a 65kW wind generator (a QF). The Sweckers and Midland have battled since then over various issues relating to the financial arrangements between Midland and the QF including interconnection charges and calculation of avoided cost rate. FERC has declined twice to initiate an enforcement action against Midland.

The most recent proceeding began on May 6, 2011, with the Sweckers petitioning FERC to enforce PURPA against Midland and the State of Iowa. The proceeding continued with multiple filings, and on December 9, 2011, the Sweckers alleged trespassing and padlocking of Sweckers' disconnection switch. Midland countered the disconnection actions were permitted by the Iowa IUB and were within IUB's jurisdiction.

On December 15, 2011, FERC found the actions of Midland, in disconnecting service to a QF owned by the Sweckers, were inconsistent with its obligations under PURPA and ordered Sweckers' electric service be reconnected. FERC determined that an underlying dispute concerning Midland's determination of its avoided costs for purchasing the output of QF owned by the Sweckers was appropriate for resolution through settlement.

On March 21, 2013, FERC denied rehearing of its December 15, 2011, order and renewed its Intent Not to Act, finding that the actions of Midland, in disconnecting service to the Sweckers' QF, were inconsistent

with Midland's obligations under PURPA. FERC found that nothing raised in rehearing changed its view that, by disconnecting the Sweckers, Midland has not in effect terminated, at least on a temporary basis, its obligation to buy from and sell to the Sweckers.

Commissioner Clark dissented in this case, arguing that a dispute concerning disconnection of the Sweckers had been cast as a PURPA dispute but it was really a case concerning disconnection of a retail customer for nonpayment that was within the state commission's jurisdiction.

Current Status

FERC indicated in its denial of rehearing and Renewal of its Notice of Intent Not to Act that Midland has acted inconsistently with PURPA but it will not to go court on behalf of the Sweckers. On May 17, 2013, Midland appealed FERC's order to the United States Court of Appeals for the District of Columbia Circuit. The Iowa Utilities Board NRECA and NARUC have intervened.

Minnesota

Key Issue

A QF has challenged the Minnesota statute's consistency with FERC's PURPA regulations concerning calculation of avoided cost.

Summary

On March 18, 2013, Gadwall Wind (QF) petitioned FERC to initiate enforcement against the Minnesota Public Utility Commission (MPUC), asking FERC to remedy an alleged improper implementation of PURPA on the part of Minnesota's legislature. In its petition, Gadwall challenged Minn. Stat. §216B.164, saying it is inconsistent with PURPA and FERC's implementing regulations because it provides that avoided costs calculated for QFs in Minnesota should be based on the "lower of" a purchasing utility's: (1) least-cost renewable energy facility; or (2) the bid of a competing supplier of least cost renewable energy facility. Gadwall contends the statute permits what it characterizes as "price inversion" for renewable QFs, which Gadwall describes as an avoided cost that is below the cost associated with a purchasing utility's "highest marginal cost" generation unit that is displaced by the QF. As such, Gadwall asked FERC to initiate an enforcement action against the MPUC to revise and/or invalidate Minn. Stat. § 216B.164, subd.

On April 26, 2013 NARUC filed comments in this FERC proceeding and stated that Gadwall is challenging the Minnesota statute and is alleging fault on the part of the Minnesota legislature, a body over which the Minnesota PUC has no jurisdiction. NARUC contends that Gadwall does not appear to challenge any action on the part of the Minnesota PUC related to PURPA implementation, and as such Petitioner's request for enforcement by FERC is without merit.

Further, the MPUC reiterated in comments to FERC that the petition should be dismissed for lack of jurisdiction because it fails to state a proper claim for enforcement under PURPA Section 210. It maintains that the Minnesota legislature has vested the Minnesota PUC with all Minnesota electric utility ratemaking authority and Gadwall cannot cite to any Minnesota PUC rule of order that fails to properly implement the Commission's rules under PURPA.

Current Status

FERC has not yet acted in this proceeding.

Oregon

Key Issue

The key issue is whether the QF (Kootenai) located in Idaho is eligible for an Oregon PURPA contract because it proposes to deliver its QF's output to Idaho Power in Oregon. Kootenai states that since it does not interconnect to Idaho Power in Idaho, Kootenai is eligible for an Oregon PURPA contract as an indirect sale since it delivers its QF's output to Idaho Power in the state of Oregon. Idaho Power protested and does not dispute Kootenai's eligibility for an Idaho PURPA contract, but says the contract must be governed by the process, pricing, and agreements approved by the Idaho PUC.

Summary

On April 16, 2013, Kootenai Electric Cooperative filed a petition asking FERC to take action to correct an Oregon Public Utility Commission (OPUC) Order, of February 26, 2013, concerning sale of electric output from Kootenai's Fighting Creek Landfill Gas Station, and that FERC find that the OPUC order violates FERC's August 31, 2012 *Avista* order, and PURPA regulations.

The fundamental dispute in the OPUC proceeding is whether Kootenai is eligible for an Oregon PURPA contract because Kootenai proposes to deliver its QF's output to Idaho Power in Oregon. Kootenai argued that it is delivering its QF's output to Idaho Power at the point of change in ownership (which is near Imnaha, Oregon) on the 230 kilovolt transmission line which runs between the Avista-owned Lolo substation in Idaho and the Idaho Power-owned Oxbow substation in Oregon.

On June 14, 2013 FERC issued a Notice of Intent Not to Act and Declaratory Order, but said that Kootenai may bring its own enforcement action against OPUC in the appropriate U.S. district court. However, FERC found that the Oregon Order is inconsistent with PURPA in certain respects. FERC found that the Oregon Order terminating Kootenai's wheeling transaction at a Lewiston, Idaho point of delivery (POD) has misinterpreted the Commission's August 31 Order that accepted the *Avista* Agreement. FERC said that the issue for PURPA purposes is not so much the designation of the POD, but rather whether the QF can deliver its output to Idaho Power. The June 14 Order determined that the point of delivery designated for delivery of Kootenai's output to Idaho Power, the Lolo substation in Idaho, is not the point where delivery actually occurs.

Current Status

On July 15, 2013, Idaho Power sought rehearing of FERC's order.

Vermont

Key Issue

The key issue is whether the optional feed-in tariff (FIT) program in Vermont that does not utilize avoided cost methodology violates PURPA if there is an alternative program implementing PURPA in Vermont.

Summary

Otter Creek (a QF) is developing a 2-megawatt solar farm in Rutland County, Vermont. On May 1, 2013, Otter Creek filed a petition for enforcement, asking FERC to initiate enforcement against the Vermont Public Service Board (VPSB) to remedy issuance of a series of VPSB orders which implemented a FIT program, called the Sustainably Priced Energy Enterprise Development or SPEED Program. Otter Creek said the SPEED Program is contrary to the requirements of PURPA because it:

- fixes the wholesale price for the purchase of power from a qualifying facility (QF) at a price that has not been determined to be the utility's avoided costs;
- sets a wholesale price for energy for utilities that are not subject to PURPA;

- creates a policy, which constitutes a de facto rule with respect to rates under PURPA Section 210(f)(1), that eliminates a QF's ability to seek an avoided cost long-run rate pursuant to 18 C.F.R. §292.304(d)(2)(ii) except through the SPEED Program;
- forces QFs to contract with an entity that is not the utility that has the obligation to purchase under PURPA; and
- sets aside a certain amount of new capacity for utility-owned projects, thus eliminating the ability of QFs to specifically displace that new capacity.

On June 27, 2013, FERC issued a Notice of Intent Not to Act, declining Otter Creek Solar's request to initiate enforcement action against the VPSB. Though FERC offered little explanation for its decision, it said that VPSB's standard offer SPEED program is an optional program available to certain small renewable QFs. Further, QFs may participate in the Vermont Commission's longstanding Rule 4.100 program which is Vermont Commission's implementation of PURPA. Rule 4.100 has been found by FERC to be consistent with PURPA. In Vermont, QFs thus still have the option to participate in a program that has been found consistent with PURPA. Those Vermont QFs that choose to participate in the SPEED program are agreeing to the rates that result from the program.

Current Status

On July 24, 2013, Otter Creek sought rehearing of FERC's order denying its petition.

PHILIP D. MOELLER

Commissioner Philip D. Moeller is serving his second term on the Commission, having been nominated by President Obama and sworn in on July 16, 2010, by Congresswoman Cathy McMorris Rodgers (R-Wash.), for a term expiring June 30, 2015. He was first nominated to FERC by President George W. Bush in 2006 and sworn into office on July 24, 2006, by Chief Justice of the United States John Roberts.

From 1997 through 2000, Mr. Moeller served as an energy policy advisor to U.S. Senator Slade Gorton (R-Washington) where he worked on electricity policy, electric system reliability, hydropower, energy efficiency, nuclear waste, energy and water appropriations and other energy legislation.

Prior to joining Senator Gorton's staff, he served as the Staff Coordinator for the Washington State Senate Committee on Energy, Utilities and Telecommunications, where he was responsible for a wide range of policy areas that included energy, telecommunications, conservation, water, and nuclear waste.

Before becoming a Commissioner, Mr. Moeller headed the Washington, D.C., office of Alliant Energy Corporation. Prior to Alliant Energy, Mr. Moeller worked in the Washington office of Calpine Corporation.

Mr. Moeller was born in Chicago, and grew up on a ranch near Spokane, Washington.

He received a B.A. in Political Science from Stanford University.

The U.S. electric utility industry is faced with a number of critical environmental policy and regulatory issues that are impacting company strategic planning and decision-making. In combination with continued low natural gas prices, slow economic growth, increased use of renewable energy and an aging fleet, these issues are spurring major investment in electric power generation and transmission. For example, more than 60 gigaWatts (GW) of publicly announced coal plant retirements could take place between 2010 and 2022. In addition, 15 GW of wind and solar came online in 2012, and more than 21 GW of new gas-fired generation were announced.

The September CEO meeting will feature updates and discussion on several key environmental issues, including the § 316(b) cooling water intake structures rule and greenhouse gas new source performance standards.

EEI Board Leads:

Gerard M. Anderson, Chairman, President & CEO, DTE Energy Co.
Ralph Izzo, Chairman, President & CEO, Public Service Enterprise Group Inc.

§ 316(b) Cooling Water Intake Structures Rule

EPA signed another amended settlement agreement with Riverkeeper delaying release of the final § 316(b) rule to November 4. The delay was approved partly to allow EPA time to consult with the National Marine Fisheries Service and U.S. Fish and Wildlife Service on the rule's impact on endangered and threatened species. It also allows EPA to begin a Science Advisory Board (SAB) process to review the stated preference survey used in assessing the proposal's non-use benefits. The consultation will be completed by November 4, although SAB reviews typically last a year or more.

The draft final rule went to OMB at the end of July, suggesting that the substantive aspects of the rule are complete. Accordingly, a limited, representative group of CEOs will meet with senior administration officials to discuss the 316(b) rulemaking, and will emphasize: deleting or revising the numeric impingement mortality standards; including of a multi-prong approach to achieve compliance; reducing compliance requirements for facilities with *de minimis* impacts and low-use units; obtaining an adequate definition of what constitutes existing units and new units at facilities; improving the definition of closed-cycle cooling; eliminating use of the willingness-to-pay survey and its results as a tool for assessing non-use benefits; and eliminating overaggressive Endangered Species Act review. The CEO group also will underscore why these issues warrant continued efforts to ensure that a final rule does not create an uneconomic path forward for facilities. Together with the improvements to impingement mortality contained in last year's NODA, these improvements would provide broad flexibility and allow for use of alternative compliance approaches.

EEI has summarized the intelligence we have received to date on the rule. The draft final rule continues to trend favorably in many respects. Flexible compliance options are afforded, reduced monitoring requirement are favored, the national numeric impingement standard has been relaxed and facilities with *de minimis* impacts may be given reduced compliance requirements. There has been a slight easing on what defines a closed-cycle cooling systems. Some important issues remain unresolved, such as the definition of new units at existing facilities and whether the rule provides any compliance flexibility for low capacity units. After the final rule is promulgated, there is a high probability that it will be litigated. Industry likely will want to protect its interests by being party to the litigation, rather than just an intervenor and thus subject to being excluded from any possible settlement discussions.

Additional Resources:

- 316(b) Strategic Environmental Issue Summary
  http://www.eei.org/issuesandpolicy/environment/MemberDocuments/CEOBoardBook/September2013/PCE082313CWISissuepaper.pdf
- EPA's Draft Final Cooling Water Intake Structure 316(b) Rule – Key Issues
  http://www.eei.org/issuesandpolicy/environment/MemberDocuments/CEOBoardBook/September2013/316CEOPositionSummary_final.pdf

Greenhouse Gas New Source Performance Standards

As part of the June 25 Climate Action Plan release, President Obama directed EPA to repropose greenhouse gas (GHG) new source performance standards (NSPS) for new fossil fuel-based units by September 20, and to finalize those standards as soon as possible thereafter. In July, EPA sent the reproposed standards for new sources to OMB for interagency review. It is expected that the reproposal includes separate standards for coal and natural gas plants, and that the standard for coal units will require some level of carbon capture. EEI has summarized key issues and anticipated changes in the new source reproposal.

EEI expressed its position on standards for new units in June 2012 comments on EPA's original proposal to set a single standard of 1000 lb/MWh for all new fossil units. In those comments, EEI expressed concern that: the NSPS effectively precludes the building of new coal-based power plants, as they would have to install CCS, which has not been commercially demonstrated at scale; and some new natural gas combined-cycle (NGCC) units may not be able to meet the standard continually under normal, real-world operating conditions. EEI urged EPA to set a separate, achievable standard for new coal-based power plants, and to raise the emissions standard for new NGCC units or take other steps to address NGCC concerns. EEI also supported an exemption for simple-cycle units. Notwithstanding changes EPA has made in the reproposal, EEI's 2012 position on the new source standards will continue to guide efforts in assessing and responding to the reproposal.

Once EPA issues the reproposed standards for new units, it is expected to develop draft state guidelines for existing (and probably modified and reconstructed) plants (collectively referred to as "existing plants") under section 111(d) of the Clean Air Act. The President directed EPA to issue proposed standards for existing plants by June 2014 and to finalize them by June 2015. As EPA moves forward, it is important that any rulemaking minimize the impact on existing EGUs that are making significant investments to comply with MATS and other EPA rules. In anticipation of future CEO consideration, EEI has engaged in an extensive educational effort with member company staff, exploring key technical and legal issues, and reviewing proposals put forward to date by various stakeholders. Recent activity is summarized in a July 2 note to the Environment Executive Advisory Committee (EEAC). Given the President's June Climate Action Plan, EPA may well take an aggressive approach to reductions at existing units. Similar to the process followed for MATS and other rules, as EPA moves forward in

developing existing source standards, members will have to identify consensus policy and strategy positions. Towards that end, EEI has produced an initial summary of key issues identified through legal and technical analyses undertaken by the EEAC to date.

CEO level involvement will be crucial in trying to shape both the new source and existing source standards. CEOs will be asked to approve refinements to EEI's existing positions on key issues related to the NSPS for new fossil fuel-based units. CEO actions likely will include additional meetings with EPA and other Administration officials on both the new and existing source standards.

Additional Resources:

- GHG Regulation Under the Clean Air Act Strategic Environmental Issue Summary http://www.eei.org/issuesandpolicy/environment/MemberDocuments/CEOBoardBook/September2013/PCE082313GHGCAAissuepaper.pdf
- EPA's Reproposed GHG NSPS for New Electric Generating Units – Key Issues http://www.eei.org/issuesandpolicy/environment/MemberDocuments/CEOBoardBook/September2013/GHGNSPS-EPA_New_Unit_Reproposal_KeyIssues082313.pdf
- Quin Shea July 2 note to EEAC with Action Items http://www.eei.org/issuesandpolicy/environment/MemberDocuments/CEOBoardBook/September2013/GHGNSPS-EEACmemo070213.pdf

Effluent Guidelines

In June, EPA proposed the first significant revision of the Clean Water Act (CWA) steam electric effluent limitation guidelines (ELGs) in 30 years. Comments on the proposal are due by September 20, and EPA is obligated through a settlement agreement to finalize the rulemaking by May 2014. The rulemaking sets strict technology-based effluent limitations that will force technological and operational changes at existing coal-based facilities, many gas-based combined-cycle facilities, and some nuclear generation facilities. Environmental groups have organized an extensive grassroots public comment campaign and published numerous reports alleging significant environmental damage in an effort to impact the rulemaking. A white paper containing press talking points has been distributed to your staffs.

In the proposal, EPA focuses on seven major wastestreams: (1) flue gas desulfurization (FGD) wastewater, (2) bottom ash transport water, (3) fly ash transport water, (4) combustion residual leachate, (5) non-chemical metal cleaning wastewaters, (6) gasification wastewater, and (7) flue gas mercury control wastewaters. EPA has considered different technology options for each wastewater and outlines eight regulatory options, of which four are preferred.

The four preferred options differ primarily in stringency for FGD wastewater and bottom ash transport water—the two most strategically important wastestreams. For FGD wastewater, preferred options range from relying on best professional judgment (BPJ) to requiring chemical precipitation plus biological treatment for some or all units. For bottom ash transport water, EPA generally would allow impoundments, though one preferred option would require dry handling at units larger than 400 MW. EPA expects facilities to be in compliance no later than July 2022, and in some instances, immediately after the final rule becomes effective.

All options would establish numeric effluent limits for constituents such as mercury, arsenic, selenium, and total dissolved solids. The proposal also addresses "legacy" wastewaters generated prior to the rule's compliance deadlines and imposes stringent best management practices for coal combustion residual (CCR) surface impoundments. EPA has indicated that it intends to coordinate the CCR

rulemaking with the ELG rule, and that facilities should be able to evaluate the requirements of both rules prior to any deadlines for retrofitting or closing surface impoundments.

Revised ELGs must set reasonable limits achievable for a broad range of facilities using affordable and feasible technology. In comments that will be filed later this month, EEI and UWAG will document how EPA has overestimated the harm caused by power plant effluents, and overestimated the benefits of the proposed rule by using old, unrepresentative data and biased assumptions. Industry believes that EPA must revise its technical approach to evaluating the covered wastestreams and rely on more current and reliable data. The final rule must provide reasonable compliance schedules (e.g., 8-10 years) to facilitate compliance with this and other pending rulemakings.

Additional Resources:

- ELG Strategic Environmental Issue Summary
  http://www.eei.org/issuesandpolicy/environment/MemberDocuments/CEOBoardBook/September2013/PCE082313ELGissuepaper.pdf

Coal Combustion Residuals Regulation

In June 2010, EPA proposed two primary regulatory options for CCR disposed of in landfills or surface impoundments: (1) regulation as hazardous wastes under Subtitle C of the Resource Conservation and Recovery Act (RCRA); or (2) regulation as non-hazardous wastes under Subtitle D of RCRA. Under both options, proposed regulatory requirements would lead to the closure of existing surface impoundments, although the Agency's so-called "D Prime" option would allow the use of existing surface impoundments so long as environmental and safety standards are met. EPA has indicated that the final coal ash rule likely would not be issued until 2014 because of the complex nature of the ash rule, and the Agency's intention to coordinate the ash rule with the Clean Water Act ELG rulemaking that is scheduled to be finalized May 2014.

Environmental organizations and ash marketers have separately filed lawsuits seeking to compel EPA to complete expeditiously the current rulemaking, with the former wanting EPA to finalize a Subtitle C-based rule, and the latter concerned with the ongoing erosion of market share due to regulatory uncertainty. USWAG is an intervenor in one of the lawsuits, and is arguing that the case be dismissed. Briefing was completed in December 2012, and a status conference is scheduled for October 11, 2013. Should the court find for the plaintiffs, or EPA settle the case, the rulemaking deadline could limit interagency review of the final ash rule.

On July 25, the House of Representatives passed H.R. 2218, the Coal Residuals Reuse and Management Act, with strong bipartisan support by a vote of 265 to 155. EEI and its allies are working to build support for this critical legislation, and continuing a dialog with Congressional leaders to develop and implement a strategy to move the legislation through the Senate.

CEOs are asked to continue to advocate the non-hazardous waste regulation of CCR under state, rather than federal regulatory control; to develop and strengthen third-party support for non-hazardous regulation of CCRs; and to coordinate with Members of Congress, federal agencies, state officials and other stakeholders in support of the current legislative effort.

Additional Resources:

- CCR Strategic Environmental Issue Summary
  http://www.eei.org/issuesandpolicy/environment/MemberDocuments/CEOBoardBook/September2013/PCE082313CCRissuepaper.pdf
- White paper – Just the Facts: Coal Ash Regulation
  http://www.eei.org/issuesandpolicy/environment/MemberDocuments/CEOBoardBook/September2013/JusttheFactsonNGOReportonWater.pdf

Cross State Air Pollution Rule (CSAPR)

On June 24, the Supreme Court granted petitions seeking review of the D.C. Circuit's August 2012 decision that vacated and remanded CSAPR to EPA. Briefing is schedule for this fall, with a court decision expected by mid-2014. As directed by the D.C. Circuit, EPA continues to administer the Clean Air Interstate Rule (CAIR) during litigation addressing CSAPR.

On July 30, EPA Acting Assistant Administrator for Air and Radiation Janet McCabe briefed EEI on the Agency's activities to replace CSAPR. EPA said it would issue a proposal by June 2014 to address regional transport related to the 2008 ozone standard in the Eastern part of the country. EPA will define states emissions reductions obligations, but it will be up to the states to decide which sources (EGUs and non-EGUs) to control further. EPA's rule will not address emissions trading but state programs could. EPA has held initial outreach sessions with trade associations and affected states. EPA acknowledges that the outcome of their Supreme Court appeal could change this plan.

Additional Resources:

- Interstate Transport & Multi-Emissions Policy Strategic Environmental Issue Summary
  http://www.eei.org/issuesandpolicy/environment/MemberDocuments/CEOBoardBook/September2013/PCE082313TransportMEissuepaper.pdf

Regional Haze

EPA has reviewed and will take action on almost all state regional haze plans by the end of 2013, including unit-specific best available retrofit technology (BART) determinations. Individual SIP and FIP requirements for BART can have major financial implications for companies, despite little or undetectable visibility benefits in many cases. An EEI CEO work group has directed industry efforts to constructively affect this policy issue on both a programmatic and state-by-state basis, including meetings with EPA and other Administration officials.

There continues to be a mix of positive and troubling decisions on regional haze. On the positive side, in New Mexico, EPA has partially backed away from its initial efforts to impose very strict plans. Unfortunately, EPA has issued adverse decisions for power plant BART in Arizona and Wyoming; and, the 10^{th} Circuit Court of Appeals denied petitions to review EPA's BART FIP. Finally, the vacatur of CSAPR negates the June 2012 EPA rule that CSAPR compliance can satisfy BART requirements, creating uncertainty for many Eastern states as to BART obligations for affected units.

As part of its FY 2014 Appropriations bill, the House Interior and EPA Appropriations Subcommittee approved EEI-supported language directing EPA to update two key regulatory visibility modeling and cost estimation tools used in Regional Haze decisions. The language is identical to House-passed

language developed and advocated by EEI in 2012. The FY 2014 bill is currently pending before the full House Appropriations Committee.

National Ambient Air Quality Standards

EPA's schedule to propose a tighter ozone National Ambient Air Quality Standard (NAAQS) has slipped from late-2013 to mid-2014 (although pending litigation seeks to force quicker action). EPA's 2008 ozone standard addressing impacts on vegetation (the secondary standard) was recently remanded to EPA for further justification. Revised ozone standards in 2015 will result in new non-attainment areas and state plans requiring new control measures for EGUs. The House of Representatives Science Committee held a June hearing questioning the achievability of a tighter standard.

EPA recently tightened the health-based annual fine particulate matter ($PM_{2.5}$) NAAQS) effective on March 18, and states are due to propose to EPA which areas fail the new standard in December. Implementing the new $PM_{2.5}$ NAAQS, along with recent 1-hour NAAQS for both nitrogen dioxide and sulfur dioxide (SO_2), has proved challenging. New and modified sources are finding it difficult to obtain air quality permits, partly due to conservative air quality modeling requirements. New and modified plants in non-attainment areas face the ultimate challenge of meeting "lowest achievable emission rate" requirements and obtaining scarce and very expensive emissions offsets.

EPA recently declared that 29 areas in 16 states fail the 2010 SO_2 standard in the first of several steps to designating non-attainment areas. Tighter NAAQS likely will be addressed in new interstate transport rules, and lead to new state planning for additional control measures for power generators beyond those required by MATS and CAIR/CSAPR, with an increased impact in the West.

Transmission Siting

New electric transmission is needed for enhanced reliability, to serve regional markets, and deliver electric power from renewable energy projects to load centers. The Energy Policy Act of 2005 included provisions to improve the siting and permitting of transmission lines on federal lands. Unfortunately, those improvements have been slow to be implemented, or once utilized, impeded by court challenges.

In 2011, the White House's Council on Environmental Quality (CEQ) created a nine agency Rapid Response Team for Transmission (RRTT) to find ways to improve the performance of federal permitting and review processes for infrastructure development. Working on seven pilot projects, the RRTT developed a set of recommendations for streamlining and improving permitting processes. Building on the work of the RRTT, the President's March 2012 Executive Order 13604, "Improving Performance of Federal Permitting and Review of Infrastructure Projects," directed a federal agency Steering Committee to develop a Federal Permitting and Review Performance Plan. In practice, the RRTT and the Steering Committee are comprised of the same principals.

In April, CEQ held an invitation-only Stakeholder Workshop on Transmission Permitting and Review to discuss the RRTT's findings and to unveil an Integrated Interagency Pre-Application (IIP) Process for transmission. With help from EEAC Chair Caroline Choi, EEI helped convene an industry panel that articulated the industry's position on the need for improved siting and permitting processes and provided input on the proposed IIP Process. In June, EEI delivered a letter to CEQ Chair Sutley supporting and endorsing key elements of the IIP Process that would improve the way transmission projects are currently sited and permitted. EEI also expressed our desire that any pre-application process be codified through a formal rulemaking.

Also in June, President Obama signed a Presidential Memorandum (PM), "Transforming our Nation's Electric Grid through Improved Siting, Permitting, and Review." The PM builds on the improvements identified by the RRTT and directs the Steering Committee to "develop an integrated, interagency pre-application process for significant onshore electric transmission projects requiring federal approval." The Steering Committee is required to submit a plan for implementing improvements to CEQ by September 30, 2013. EEI has recommended that the Steering Committee incorporate the proposed IIP Process as they develop a pre-application process. In July, EEI met with CEQ and the Bureau of Land Management (BLM) to press for continued progress in meeting the PM directives for improved siting, permitting and review.

Additional Resources:

- Transmission Siting Strategic Environmental Issue Summary
  http://www.eei.org/issuesandpolicy/environment/MemberDocuments/CEOBoardBook/September2013/PCE082313TMSitingissuepaper.pdf

Avian Protection

The avian protection issue is managed for the industry by the Avian Power Line Interaction Committee (APLIC). APLIC currently is addressing issues related to the Bald and Golden Eagle Protection Act, potential listing of the greater sage grouse and lesser prairie chicken under the Endangered Species Act (ESA), and development of utility specific conservation measures for the six state migration corridor for the whooping crane. APLIC continues to meet with USFWS staff and BLM to improve the implementation rules for bird protection. APLIC presented the Avian Interactions with Power Lines Workshop in August 2013 at the request of the Texas Parks and Wildlife Department. APLIC also will present a September 23-24 training workshop, hosted by PHI Inc., in New Jersey.

Additional Resources:

- Avian Protection Strategic Environmental Issue Summary
  http://www.eei.org/issuesandpolicy/environment/MemberDocuments/CEOBoardBook/September2013/PCE082313Avianissuepaper.pdf

The Endangered Species Act (ESA) and Climate Change

EEI and other stakeholders are concerned about what they see as a "sue-and-settle" strategy to list species under the ESA. The concern is a result of the May 2011 litigation settlement between the USFWS and WildEarth Guardians, which required the USFWS—for all 251 species on the candidate list—to propose to list (as threatened or endangered) or to find that a listing is not warranted. These kinds of settlements deny stakeholders a chance to participate negotiations. To date, courts have denied industry attempts to intervene. Many in Congress find the "sue and settle" strategy troubling and are currently working on legislation to address the issue. In the meantime, new listing proposals resulting from the settlement will require attention if they could affect siting of transmission and other utility facilities.

The polar bear ESA 4(d) rule has been EEI's major focus on the interplay between ESA and climate change. The USFWS published its final ESA §4(d) rule for the polar bear on February 20, 2013. While the final rule is positive for EEI members, the Center for Biological Diversity (CBD) has formally filed its intent to sue USFWS over the polar bear listing, stating the polar bear population has declined to the

point where the species should be listed as "endangered" rather than "threatened." A listing as "endangered" would render void the current positive 4(d) rule in place for the polar bear, which excludes activities outside the artic from consideration when assessing species impacts.

In addition to the polar bear, environmental groups are continuing efforts to use the ESA to attempt to achieve GHG emissions reductions. The groups have petitioned the USFWS and the National Marine Fisheries Service (NMFS) to list penguins, pacific walrus, ring seals, and the American pika for protection under the ESA, claiming global climate change is significantly diminishing essential habitat for these species, putting them at risk of extinction.

Pending listing decisions for the lesser prairie chicken, Gunnison sage grouse, and the greater sage grouse have significant implications for the siting and maintenance of power lines, renewable generation, and other energy facilities. EEI and APLIC are actively involved in these issues. APLIC also is developing best management practices for utilities operating in greater sage grouse habitat.

Additional Resources:

- Endangered Species Act Climate Change Strategic Environmental Issue Summary
  http://www.eei.org/issuesandpolicy/environment/MemberDocuments/CEOBoardBook/September2013/PCE082313ESAClChgissuepaper.pdf

Environmental Regulatory Challenges: *2013 and Beyond*

Air	Climate	Water	Land & Natural Resources	Waste & Chemical Management
Mercury & Air Toxics (MATS)	NSPS- New Sources	316(b)	Transmission Siting and Permitting	Coal Ash
Interstate Transport (CAIR/CSAPR)	NSPS- Existing Sources	Effluent Guidelines Limitations	Avian Protection	PCBs in Electrical Equipment
Regional Haze/Visibility	BACT Permitting	Waters of the United States	Endangered Species	HazMat Transport
Multiple NAAQS	International Negotiations	Total Maximum Daily Loads	Vegetation Management	
New Source Review (NSR)		Waterbody-Specific Standards		

Coal Fleet Announcements

Following is a summary of announced retirements of coal plants under which approximately 63,000 MW of generation capacity (or 18.5% of the 339 GW of total coal-fired generation capacity in 2010) will be retired between 2010 and 2022.[1] Some units will be replaced or repowered with natural gas generation.[2]

Company	Total MW	State	Year(s) Built	Year(s) Will Retire	Units Retiring/Notes
AEP[3]	7,991	Various	1944-1980	2011-2016	30 units in 7 states (converting some to NG)
AES	1,061	NY, OH, IN	1948-1961	2011-2017	14 units (converting 2 units to natural gas)
Allete	186	MN	1953-1957	2015	3 units
Alliant	1,112	IA, WI	1921-1969	2010-2018	19 units
Ameren[4]	1,277	MO, IL	1953-1961	2011, 2022	7 units
APS	633	AZ	1963, 1964	2015	3 units
Black Hills	124	various	1948-1969	2012-2014	7 units (CO, WY, SD)
Consumers[5]	971	MI	1952-1958	2015	7 units
Dominion[6]	2,515	MA, IN, VA	1952-1992	2013-2022	17 units
DTE[7]	272	MI, CA	1952-1989	2010-2013	5 units
Duke[8]	7,836	various	1940-1978	2011-2020	50 units (FL, IN, NC, OH, SC)
Dynegy	489	IL	1953-1959	2011-2013	4 units
Edison Int'l[9]	1,239	IL	1955-1968	2010-2014	5 units
Empire District	88		1950, 1954	2016	2 units
Exelon	895	PA	1954, 1960	2011-2012	3 units
First Energy[10]	5,806	various	1944-1972	2010-2015	28 units (MD, OH, PA, WV)
GenOn[11]	3,493	OH, PA, VA	1949-1970	2012-2015	25 units
Great Plains	170	MO	1958	2016	1 unit
Madison G&E	178	WI	1938-1961	2010-2012	5 units
MidAmerican	1,279	UT, IA, WY	1925-1971	2015-2016	10 units (converting 4 units to natural gas)
NiSource[12]	629	IN	1950-1970	2010-2012	6 units
NRG	1,075	DE, MA, NY	1950-1970	2010-2014	8 units
NV Energy	342	NV	1965, '68, '76	2016	3 units
PGE	601	OR	1980	2020	Will retire Boardman plant 20 years early
PNM	738	NM	1973, 1976	2017	2 units
PPL	1,062	KY, MT	1953-1969	2015	7 units
SCANA	770	SC	1953, '58, '62	2012-2018	6 units
Southern[13]	9,954	Various	1949-1967	2011-2020	16 units
TransAlta[14]	1,460	WA	1971	2019-2024	2 units (Centralia)
TVA[15]	3,304	TN, AL, KY	1952-1965	2012-2019	21 units
WE Energies	280	WI	1968, 1969	2015	2 units (converting to natural gas)
WPS	247	WI	1949-1960	2015	4 units
Xcel Energy[16]	1,431	CO, MN	1951-1968	2010-2022	12 units
Others	3,168	various	1939-2004	2010-2022	
	62,673				

[1] Retirements are taking place for a variety of reasons, including plant age, fuel prices (i.e., low natural gas prices), decreased demand, consent decrees and the settlement of EPA complaints, the projected cost of complying with pending EPA regulations, etc. Because

some plant closure details and/or plans for replacement generation have not been finalized, it is not possible to determine the exact number of closures, the mix and quantity of generation replacing the retiring coal units, or the exact amount of emissions reductions.

[2] To the degree that retiring coal plants are replaced or repowered with natural gas generation, mercury and SO_2 emissions will be virtually eliminated and CO_2 emissions reduced by almost half at those units.

[3] On 6/09/11, AEP announced that as part of its plan for complying with EPA regulations, it would retire 6,000 MW of coal-fired generation—some of which will be replaced with natural gas units—belonging to its following subsidiaries: Kentucky Power, Indiana Michigan Power, Southwestern Electric Power, Ohio Power, Columbus Southern and Appalachian Power. Some of the plant retirements are part of a settlement agreement with EPA. On 12/19/12, AEP announced that it would close Big Sandy 2 (800 MW).

[4] Ameren, in Feb. 2011 IRP filing in MO, indicated it would likely close Meramec 1-4 due to the cost of meeting pending EPA regulations.

[5] Consumers Energy indicated, in a Dec. 2 press release, that it did not anticipate operating the 7 units past Jan. 1, 2015, but that market conditions and the final form and timing of federal and state environmental regulations could lead it to adjustment of its plans.

[6] Dominion is retiring 17 units due in part to cost of complying with the pending EPA regs (Salem Harbor, State Line, Chesapeake, Yorktown); 4 units are being retired due to low natural gas prices; 3 units (Altavista, Hopewell, and Southhampton) are being converted to biomass and 2 to natural gas (Bremo Bluff, Yorktown). Some of these closures were included in a September 1, 2011, IRP filing.

[7] DTE Energy Services has agreed to covert 2 coal-fired facilities to biomass—the Port of Stockton Energy Facility and the Mount Poso Cogeneration Plant (co-owned with Red Hawk Energy)

[8] Data includes retirements announced by then-Progress Energy, now a part of Duke. The Beckjord 6 unit, which is co-owned with AEP subsidiaries Columbus Southern and Dayton Power & Light, is included in the Duke total. As part of its overall coal-fleet transition strategy, Duke announced an agreement in 2008 to retire 800 MW of coal-fired power in exchange for building new 825 MW clean coal facility at Cliffside. It is not clear which plant retirements relate to this announcement, with the exception of Cliffside 1-4. Duke also agreed to make the new facility carbon neutral by 2018 by offsetting approximately 5½ million tons of CO_2/year) through the following means: depending more on nuclear power, further reducing power generated by coal-burning units, and using energy efficiency programs, carbon free tariffs and other "mitigation projects." The new unit will: remove 99% of SO_2, 90% of NOx emissions and cut mercury emissions by 50%; be built to accommodate installation and operation of carbon control technologies; significantly minimize thermal impacts to the local river; and, generate wall board quality gypsum from the wet scrubber.

As part of an overall coal-fleet transition strategy, the former Progress Energy announced an agreement in December 2009 to retire 30% of its NC fleet (11 plants or approximately 1,500 MW of total capacity), replace some with natural gas plants, build new 950-MW natural gas plant at H.F. Lee plant site and build additional new 600-MW natural gas plant at Sutton Plant to replace coal generation being retired in order to maintain reliability. Progress' remaining NC plants are scrubbed (spent $2 billion installing state-of-the-art control on remaining coal generation). The retirement of 2 units in FL (Crystal River 1 & 2) depends on approval to move forward with a new nuclear plant.

[9] Edison International is closing the units under 2 different agreements with IL, and has also agreed to install SO_2 and NOx controls on all Midwest Gen plants.

[10] On Feb. 8, 2012, FirstEnergy announced that it would retire 3 coal-fired plants in WV due to the cost of complying with the MATS regulation. On January 26, 2012, FirstEnergy announced that it would retire 6 coal-fired facilities, 2 of which—Armstrong and R. Paul Smith—had not previously been unannounced, due to the cost of complying with MATS. In August 2010, FE announced that it would retire all or part of 2 coal-fired peaking plants (Lake Shore and Ashtabula)—and reduce operations at 2 other plants (Bay Shore and Eastlake)—due to decreased demand, plant age, etc. FE is retiring 2 other units (R.E. Burger) under a consent decree with EPA.

[11] On Feb. 29, 2012, GenOn announced that it would close 7 plants due to the costs of complying with MATS.

[12] Retirement of Dean Mitchell units is part of a consent decree w/ EPA

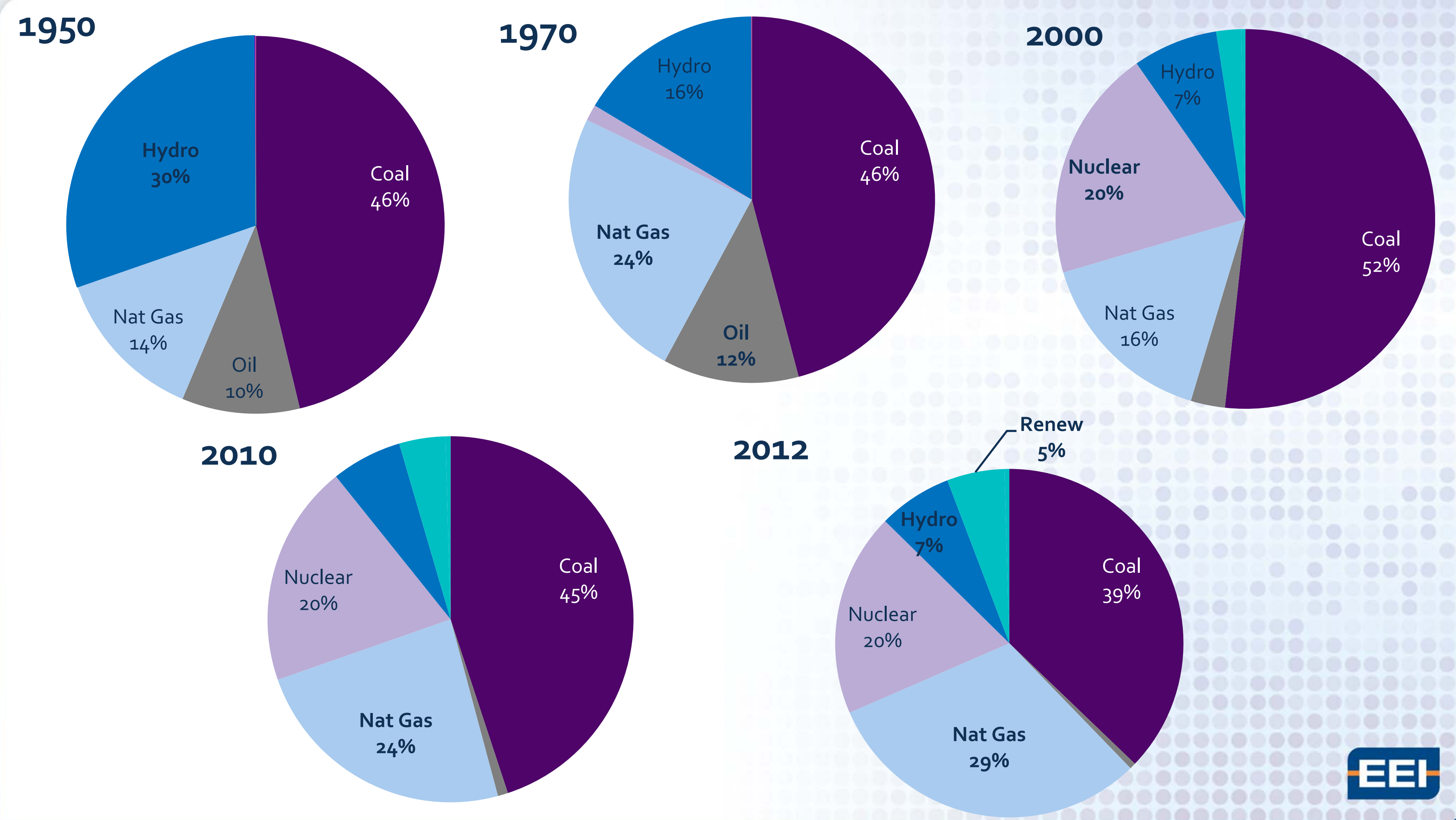
[13] Southern is retiring the plants due primarily to the cost of complying with pending EPA regs. Southern has announced plans to convert the Mitchell plant to biomass (currently on hold). On August 4, 2011, Southern filed comments that it expects to retire 4,000 MW of coal-fired generation—and repower approximately 4,700 MW of coal and oil-fired generation to natural gas and other fuels—as a result of compliance with the pending EPA regs, but has not specified which plants would be affected.

[14] Under agreement with state, TransAlta will install SNCRs on the units in 2013, invest $55 million on energy efficiency and clean energy technology development, and be allowed to sell power in-state from the plants under long-term contracts until they close.

[15] As part of settlement agreement with EPA (04/14/2011), TVA agreed to retire or idle the following coal plants: Johnsonville 1-10, John Sevier 3-4 and Widows Creek 1-6. In addition, TVA has agreed to spend $3-$5 billion in additional pollution control equipment for its remaining coal plants and $350 million on air pollution reduction and energy efficiency projects, as well as pay a $10 million civil penalty. Separately, TVA announced on 8/24/10 it would retire Shawnee 10 and John Sevier 1 & 2.

[16] In 2010, Xcel Energy announced a plan to reduce the NO_x emissions of its Colorado fleet, in response to state law that required the company to meet anticipated federal clean air regulations. Xcel Energy will invest $1 billion to retire or switch to natural gas approximately 900 MW of coal-fired generation. In addition, the company will install modern emissions controls for 950 MW of coal-fired generation. In Minnesota, the company plans to retire 270 MW at Black Dog. To date, the company has reduced regulated emissions on average 40% from 2005 levels.

Electricity Generation Mix



Coordination between Natural Gas and Electric Markets FERC Activity

In February, 2011 Commissioner Moeller issued a number of questions for industry comment on several issues related to electric/gas coordination. The request was prompted by the outages in the southwest, as well as the increasing reliance on natural gas for electric generation. EEI filed comments and urged the Commission to discuss the issues on a regional level.

FERC held 5 regional forums in August 2012 to discuss electric/gas coordination issues. FERC defined the regions as follows:

- Central (MISO, SPP, and ERCOT),
- Northeast (ISO NE),
- Southeast (Southern Company, Duke, TVA and areas south of PJM),
- West (Western Interconnection)and
- Mid-Atlantic (PJM and NY ISO).

The regional conferences highlighted the regional nature of these issues. During the conferences, some areas of commonality emerged around discrete issues of scheduling, communications and standards of conduct.

On November 15, 2012 FERC issued an order requiring Staff to convene conferences on the two primary issues identified above through additional, targeted technical conferences. The Order describes the issues as follows: The participants also identified general concerns that came up in all regions: the respective ability of each industry to share information in furtherance of enhancing gas-electric coordination consistent with the Commission's regulations on Standards of Conduct and statutory restrictions on undue discrimination and preference; and, scheduling discontinuities between the gas and electric industries, including the impact of the Commission's "no bump" and pipeline capacity release rules. The order also directed each regional transmission organization (RTO) and independent system operator (ISO) to appear before the Commission on May 16, 2013, and October 17, 2013, to share their experiences from the winter and spring, and summer and fall, respectively and for FERC Staff to monitor and engage the industries regarding progress being made within each region on natural gas and electric coordination. Staff is required to report to the Commission each quarter for 2013 and 2014 on the industries' natural gas and electric coordination activities. Staff provided its first update to the Commission on March 21, 2013, its second update on June 20, 2013 and is expected to provide its 3rd update in September.

On February 13, 2013 FERC Staff held a technical conference to identify specific areas in which additional Commission guidance or regulatory change could be considered in the area of information sharing and communications between the electric and natural gas industries. On April 25, 2013 FERC Staff held a technical conference to discuss natural gas and electric scheduling, and issues related to whether and how natural gas and electric industry schedules and practices could be harmonized to achieve the most efficient scheduling systems for both industries. Lin Frank of Indianapolis Power & Light participated at the conference on behalf of EEI and her statement, which was submitted for the record, is attached.

While both conferences continued to highlight the regional nature of these issues, the scheduling conference, in April, provided some avenues for possible FERC activity as the gas industry, for the first time, expressed a willingness to change the gas day. FERC staff take-aways from the conference and possible areas for FERC action include:

- Moving the gas day outside of the morning electric peak
- Changes to clearing times in the electric markets
- Moving the gas nomination cycle to later in the day
- Adding additional nomination cycles intra-day and/or at the end of the day
- Considering changes to no bump rule
- Considering an expansion of the capacity release rules
- Considering modification to the shipper must have title rule to relax the rule for affiliates
- Examination of FERC rules to ensure that they do not stand in the way of pipelines offering additional services.

On June 17, 2013, FERC issued a Notice of Technical Conference indicating that they would hold a technical conference on September 25, 2013 on to consider how current centralized capacity market rules and structures are supporting the procurement and retention of resources necessary to meet future reliability and operational needs in RTO and ISO markets.

On July 18, 2013, in response to statements made at the regional forum and the technical conference on information sharing and communications regarding the need for clarification on what information could be shared under the Commission's rules and regulations, issued a Notice of Proposed Rulemaking ("NOPR") on Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators. In the NOPR, the Commission proposed to revise Parts 38 and 284 of its regulations to provide explicit authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to allow them to share non-public, operational information with each other on a permissive basis for the purpose of promoting reliable service or operational planning on either the public utility's or pipeline's system subject to a no-conduit rule. EEI filed comments in response to the NOPR.

Edison Electric Institute

Power by Association℠

EEI Business Session September 12, 2013

EEI

BOARD OF DIRECTORS

Edison Electric Institute
DRAFT Minutes of the Board of Directors
and Annual Meeting
June 11, 2013

A regular meeting of the Board of Directors of the Edison Electric Institute (EEI) was held at the Marriott Marquis Hotel, San Francisco on June 11, 2013. Mr. Lewis Hay, III, EEI Chairman and Executive Chairman of NextEra Energy, presiding.

Directors Present

Lewis Hay III, Chairman
Michael Yackira, Vice Chairman
Theodore Craver, Jr., Vice Chair
Anthony Earley, Jr., Chairman Emeritus
Thomas Farrell, II, Chairman Emeritus
James Rogers, Chairman Emeritus
Gregory Abel
Nicholas Akins
Darrell Anderson for LaMont Keen
Gerard Anderson
Terry Bassham
Bradley Beecher
Gregory Butler for Charles Shivery
Christopher Crane
Peter Delaney
Leo Denault
Thomas Fanning
Benjamin Fowke
Greg Dudkin for William Spence
Ralph LaRossa for Ralph Izzo
Alan Hodnik
Jeff Householder
Scott Hudson for John Young
Craig Ivey for Kevin Burke
Christopher Johns
Patricia Leonard Kampling
Thomas King
Robert Kump
Scott Morris
John Procario
John Ramil
Richard Riazzi
Joseph Rigby
Richard Rosenblum for Constance Lau
Robert Rowe
Mark Ruelle
Mark Schiavoni for Donald Brandt
James Torgerson
Patricia Vincent-Collawn
Thomas Voss
Elizabeth Witte for Carl Chapman

Also Present

John Donleavy
Kimberly Greene
Michael Howard
Ronald Litzinger
Robert Powers

EEI Officers

Thomas Kuhn	Brian McCormack
David Owens	Richard McMahon
Brian Wolff	Mary Miller
Edward Comer	John Schlenker
John Easton	Quinlan Shea
James Fama	Kathryn Steckelberg

Board of Directors Meeting

1. Mr. Hay called the meeting to order at 7:00 a.m. on June 11.

2. Mr. Hay congratulated: Mr. Terry D. Bassham, Chairman, President & CEO of Great Plains Energy; Mr. G. Edison Holland, President & CEO of Mississippi Power; Mr. John L. Walsh, President & CEO of UGI and Mr. Jeff Householder, President of Florida Public Utilities. Mr. Hay also remarked on the passing of Mr. Donald Robinson, President & COO of Arizona Public Service.

3. Mr. Hay began with the business portion of the meeting. He called attention to the Antitrust Guidelines and Director Conflict of Interest Policy, indicating that the Secretary had informed him that a quorum was present and advised Board members where to obtain a copy of the latest financial statements.

4. The minutes of the March 2013 Board meeting were approved. Mr. Michael W. Yackira, President & CEO of NV Energy, gave the Treasurer's Report and indicated that Clifton Larson Allen had issued a clean audit opinion. The Treasurer's Report was approved.

5. Mr. Thomas R. Kuhn, EEI President, indicated that the meeting would cover environmental issues, cybersecurity, tax reform and retail and distributed resource issues. He thanked member CEOs for their active involvement. He awarded the Tony Anthony Member Unity Award to Mr. Paul A. Farr, Executive Vice-President & CFO of PPL, for active engagement in the Defend My Dividend campaign.

6. Mr. Gerard M. Anderson, Chairman, President & CEO of DTE Energy, provided a brief environmental update, while announcing that more details would be provided at the afternoon environmental session. He indicated that the expected 316(b) water intake rule would be delayed after June 28, which was the original deadline. While trending in the right direction now, we need to keep pressing forward with our messages until the rule is finalized. He stated that the issuance of the Greenhouse Gas rules would also be delayed beyond their expected early summer publication date and that proposed effluent guideline rules are expected shortly and would require detailed analysis. Finally, he expressed optimism about expected coal ash rules and potential coal ash legislation.

7. Mr. Kuhn initiated the cybersecurity report by reflecting on senior government discussions with the Chinese government. He indicated the CEOs and CIOs had numerous meetings, including with the government, to address tools and technologies, information sharing and response and recovery

activities. He discussed plans to transform the Joint Electric Executive Committee (JEEC) into the Electric Sector Coordinating Council (ESCC) to promote CEO level discussions with senior government officials and provided an overview of some of the activities and technologies being discussed. Mr. Hay and Mr. Kuhn invited members to express any concerns about information sharing with the government, but none were raised. Several members indicated government involvement had been very constructive and helped improve situational awareness.

8. Mr. Nicholas K. Akins, President & CEO of American Electric Power, discussed industry efforts to improve industry storm response and mutual assistance activities. He thanked the following members and Regional Mutual Assistance Group (RMAG) representatives for their active engagement in these processes: Mr. John J. Donleavy, Executive Vice President & COO of National Grid; Mr. Craig S. Ivey, President & COO of Consolidated Edison; Mr. William J. Quinlan, Senior Vice President, Emergency Preparedness of Northeast Utilities; Mr. Mark A. Crosswhite, Executive Vice President & COO of Southern Company; Mr. Thomas R. Voss, Chairman, President & CEO of Ameren; Mr. Keith Hull, Vice President, Distribution Operations of Oncor; Mr. Daniel K. Glover, Vice President, Power Delivery of Alabama Power; Mr. Miki Deric, Partner and Mr. Grant Davies, Founder & Partner of Davies Consulting, and Mr. Robert P. Powers, COO, and Mr. Thomas Kirkpatrick, Vice President, Customer Service, Marketing and Distribution Services of American Electric Power.

9. Mr. Akins indicated that the three Northeastern and Mid-Atlantic RMAGs have reached a preliminary agreement to consolidate. Mr. Donleavy explained that the footprints of the three RMAGS were so small that one event was likely to affect members of each at the same time, and, therefore, consolidation would help spread the risk. Mr. Akins urged all RMAGs to continually evaluate their footprint and potential consolidation.

10. Mr. Akins explained the normal RMAG process would be overridden in case of a National Response Event (NRE), which is an event that requires more resources than two RMAGs can provide. In such a case, national resources would be pooled and allocated and reallocated without regard to RMAG boundaries and processes in a transparent and equitable manner. These activities would be managed by a standing National Response Event Executive Oversight Committee (VP or above representing all regions of the US, nominated by CEOs), a Mutual Assistance Allocation Team (RMAG professionals) and an Analytical Support Team to provide a central view of the resources and track the allocation of available resources. Contractors are an important resource. There are ongoing discussions to enhance communication and coordination with contractors, including how to track contractor resources when they are redeployed. Mr. Akins emphasized the importance of clearly communicating these processes with government officials, both ahead of time and during any event. A formal mutual assistance logistics and material and equipment process will be developed and materials will be provided to help explain industry resource and delivery patterns to the public and government officials. Mr. Akins explained that the Association of Electric Illuminating Companies (AEIC) has produced a comprehensive "best practices" document and provided excellent assistance promoting best practices. Mr. Voss reported on the results of the AEIC group and congratulated Mr.

Hull and Mr. Glover for terrific work on this effort. Mr. Kuhn reported on the May meeting in which the President thanked industry CEOs for their Superstorm Sandy recovery efforts, the Department of Energy (DOE) establishment of a new emergency command and control center and planning efforts with DOE, the Department of Transportation (DOT), the Department of Homeland Security (DHS) and other agencies.

11. Mr. Akins further reported that this group would reach out to APPA and NRECA to coordinate with them in a national event. He indicated that teams were designing specific implementation criteria, developing necessary consistent communication plans and tools and planning a tabletop exercise. Mr. James Fama, Vice President, Energy Delivery of EEI, thanked the many people involved and reminded the Board that a lot of work remains to be done and it is urgent to complete the work quickly. Mr. Akins thanked the CEOs for their direct involvement, which is essential to success. Mr. Hay, Mr. Akins and Mr. Fama discussed the importance of a communications strategy with policymakers and urged members to communicate directly with their state and local officials, emphasizing the importance of CEO involvement.

12. Mr. Hay asked Mr. David K. Owens, Executive Vice President, Business Operations Group of EEI, to report on distribution issues. Mr. Owens indicated that the industry is estimated to invest $680 billion in distribution systems by 2035, making it essential for our investors, customers and policymakers to understand the need for such investments. Mr. Owens called on Mr. Robert C. Rowe, President & CEO of NorthWestern Energy, to highlight these efforts. Mr. Rowe reported that the Critical Consumer Issues Forum (CCIF), a collaboration of EEI, the National Association of Regulatory Utility Commissioners (NARUC) and the National Association of State Utility Consumer Advocates (NASUCA), established principles that can serve as a foundation for efforts to change the conversation regarding policies affecting distribution infrastructure. (Attachment A). A brief video was shown about the CCIF process.

13. Mr. Owens asked Mr. Joseph M. Rigby, Chairman, President & CEO of Pepco Holdings, to discuss a new distribution public-private partnership in the District of Columbia. Mr. Rigby reported that the June 2012 derecho served as a “tipping point” that focused on hardening techniques, including tree trimming and undergrounding. Mr. Vincent Gray, Mayor of Washington, D.C., convened a Task Force that recommended undergrounding 60 major feeders for a cost of about $1 billion. As proposed, Pepco would invest about $500 million, the District would securitize $375 in debt and the District would provide $125 million in highway funds. Mr. Rigby discussed the value of having a collaborative forum to develop these principles.

14. Mr. Owens called on Mr. Brian L. Wolff, Senior Vice President of EEI, who discussed the outreach and coalition building efforts of the Electrification Initiative. These include a co-branded campaign with GE, an EPRI business case analysis and the Electric Generation campaign and roadshow. Mr. Anthony F. Earley, Chairman, CEO & President of PG&E, emphasized the importance of electrifying utilities’ own fleets. He indicated that electric fleets promote customer and employee satisfaction due to less noise and faster repowering and have financial benefits due to less maintenance and

longer life of these fleets. Mr. Kuhn emphasized the value of adding electrified fleet vehicles and electrifying ports and terminals.

15. Mr. Hay asked Ms. Patricia K. Vincent-Collawn, Chairman, President & CEO of PNM Resources, to discuss Return on Equity (ROE) issues at FERC. Ms. Vincent-Collawn indicated that despite flat to declining loads, the industry is investing considerable amounts of capital and is facing multiple complaints seeking lower ROE levels, closer to 9%. She reported that EEI had recently issued a White Paper on ROE issues which received considerable press coverage and that groups such as the Working Group for Investment in Reliable Economic Electric Systems (WIRES) and American Wind Energy Association (AWEA) would be supporting the industry. Mr. Gregory Abel, Chairman, President & CEO of MidAmerican Energy Holdings, reported that CEOs not engaged in specific rate proceedings at FERC would engage the Commissioners personally on the ROE issues. Mr. Robert Kump, CEO of Iberdrola USA, reported on recent discussions and indicated that some Commissioners acknowledge that the Discounted Cash Flow (DCF) method has limitations.

16. Mr. Theodore F. Craver, Jr., Chairman, President & CEO of Edison International, reported on tax reform developments, noting that both House and Senate committees have completed background studies while the Senate continues work on its process. EEI's major issues are: deduction of corporate debt and normalization (if excess deferred taxes or other incentives) and financial commodity reform.

17. Mr. Christopher P. Johns, President of Pacific Gas & Electric, alerted members of complexities caused by the application of the Buy American provisions of the highway bill to related utility relocation projects. Mr. Rowe reported on his participation in advisory activities for the Senate Finance Committee.

18. Mr. Thomas F. Farrell, II, Chairman, President & CEO of Dominion, provided a Troops to Energy Jobs report about results of the pilot program phase which revealed useful information about additional support that Veterans would need before and after leaving the military to participate in energy jobs. He announced that the program was releasing a comprehensive template for recruiting, training and transition activities. A brief video was shown about the program.

19. Mr. Michael W. Howard indicated that EPRI will soon release a study showing that "all-in lifecycle" costs of electric vehicles make them very cost-competitive. These vehicles are extremely reliable and have lower maintenance costs than conventional vehicles. The EPRI Summer Seminar is titled "Innovations for Flexibility" and will address issues relating to the increased use of flexible generation.

20. Mr. Hay encouraged members to support the Edison Garage facility in West Orange, New Jersey, which houses early electric vehicles and chargers and introduced Mr. John Keegan, Chairman & President of the Charles Edison Fund & Edison Innovation Foundation, which is responsible for this project. Mr. Hay also thanked Mr. Steven A. Mitnick, Senior Energy Advisor of Bates White, for his

latest book, Lines Down, which addresses flawed assumptions about utility bills and does a good job arguing the value of investing in the grid. Finally, Mr. Hay introduced Mr. Michael Deering, Director, Development, and Mr. Patrick Ryan, Executive Director of the Power and Energy Society of IEEE who were available to discuss IEEE sponsored scholarship programs and internships, and he urged members to talk to them.

Annual Meeting

1. Mr. Hay moved into the Annual Meeting Portion of the program. The membership approved a unanimous acclamation for the election of the new Directors. (Tab A, Board of Directors Book)

2. Mr. Earley moved the nomination of Mr. Yackira as Chair and Mr. Craver, Mr. Akins, and Mr. Fanning as Vice Chairs for 2013-2014. (Tab B). The nominations were unanimously approved.

3. Mr. Yackira took the gavel, thanked members for the honor and thanked Mr. Hay for his work as EEI Chair. Mr. Yackira invited members to the evening's Grand Event.

4. The membership approved the election of Mr. Anderson, Ms. Connie Lau, President & CEO of Hawaiian Electric Industries, and Mr. Rigby to the Executive Committee (Tab C) and the election of Mr. William H. Spence, Chairman, President & CEO of PPL, as Co-Chair of the Policy Committee on Finance, and Mr. Thomas Graham, President, Pepco Region of Pepco, as the new Chair of the Center for Energy Workforce Development as well as the continuing Executive Advisory Committee Co-Chairs (Tabs D and F).

5. Mr. Brian V. McCormack, Vice President, Political and External Affairs of EEI, provided a PowerPAC report.

6. The members approved the election of the Boards of the Edison Foundation and of the Center for Energy Workforce Development (Tabs E and F).

7. The members unanimously approved the Resolution thanking Mr. Hay for his service as Chairman of EEI. A presentation of gifts followed.

8. The meeting was adjourned at approximately 9:00 a.m.

TREASURER'S REPORT

EEI Board and Chief Executives Meeting, September 2013

The 2013 regular activities budget reflects total revenue and gross operating expense of $65.8 million. As of August 15, 2013, actual year to date net operating income is slightly better than budget. Attached is the most current 2013 Statement of Operations for EEI's Regular Activities.

Separately Funded Activities, primarily supported by member companies on a voluntary basis, amount to approximately $8.2 million for 2013. Attached is the Statement of Expenses, as of August 15, 2013, for Separately Funded Activities.

The audits of the Institute's Retirement Income Plan and Cooperative Savings Plan, for the year ended December 31, 2012, are currently in progress and are on schedule to be completed later this summer. The financial statements for both plans are presented in compliance with the Department of Labor's requirements and in accordance with the Employee Retirement Income Security Act of 1974 (ERISA)

As always, copies of the Institute's audited financial statements (unmodified / clean opinion) and IRS Form 990, which were both presented to the Executive Committee by CliftonLarsonAllen at the June 2013 meeting, are available upon request.

Edison Electric Institute
Regular Activities
2013 Statement of Operations (Unaudited)

	2013 Budget	YTD as of August 15, 2013 Budget	Actual	Better (Worse) Variance
Revenues:				
Investor-owned electric utilities dues	$ 51,282,000	$ 51,282,000	$ 51,086,000	
Programs, publications and meetings	8,568,000	4,798,000	5,126,000	
Investment income	3,100,000	1,912,000	1,800,000	
International affiliates dues	1,200,000	1,200,000	1,035,000	
Associate members dues	1,176,000	737,000	752,000	
Strategic partners	500,000	500,000	500,000	
Total dues and revenues	65,826,000	60,429,000	60,299,000	(130,000)
Expenses:				
Salaries	25,254,000	15,826,000	15,420,000	
Employee benefits	14,534,000	9,108,000	8,672,000	
Programs, publications and meetings	17,256,000	10,938,000	10,828,000	
General office and administrative	8,782,000	5,503,000	5,441,000	
Total expenses	65,826,000	41,375,000	40,361,000	1,014,000
Net Operating Income	$ -	$ 19,054,000	$ 19,938,000	$ 884,000

Edison Electric Institute
Separately Funded Activities
2013 Statement of Expenses (Unaudited)

Fund Description	2013 Budget (1)	YTD as of August 15, 2013 Budget	YTD as of August 15, 2013 Actual
Industry Issues (2)	$ 5,100,000	$ 3,187,000	$ 3,171,000
Employment Testing	1,525,000	953,000	836,000
Environmental	420,000	262,000	174,000
Restore Power	475,000	297,000	422,000
Avian Power Line	230,000	144,000	123,000
Spare Transformer	288,000	180,000	206,000
Water Advocacy Coalition	122,000	76,000	67,000
Total SFA Expense, net of U-Groups	$ 8,160,000	$ 5,099,000	$ 4,999,000
Funds not controlled by EEI			
Utility Air Regulatory Group	8,343,000	5,214,000	4,940,000
Utility Solid Waste Activities Group	3,622,500	2,264,000	2,186,000

Notes:

(1) All SFA budgets are estimates and are subject to available funds contributed on a voluntary basis.

(2) The EEI Board approved a 10% voluntary assessment, based on dues, for the Industry Issues SFA.

EEI Membership Report
To the EEI Board of Directors
September 2013

1) International Affiliate Membership Change

We are pleased to inform you that we have received a new application from **United Energy** (UE) in Australia. UE distributes electricity to more than 640,000 customers across east and south east Melbourne and the Mornington Peninsula - 90% of which are residential. UE manages a network of 209,000 poles and more than 8,000 miles of wires. Electricity is received via 78 sub transmission lines at 46 zone stations, where it is transformed from sub transmission voltages to distribution voltages.

With this change, EEI will have 81 International Affiliates.

2) Associate Membership Changes

We are pleased to inform you that we have received nine applications for Associate Membership.

	COMPANY	BUSINESS
a)	Clean Power Finance James Tong Senior Director, Government Programs Management San Francisco, CA	Solar financing products and tools
b)	CTC Global Corporation Anne McDowell Director, Business Development Irvine, CA	Highly efficient conductors to increase capacity and minimize sag
c)	Electrical Consultants, Inc. Glen Smith General Manager Tucson, AZ	T&D engineering and design
d)	Faegre Baker Daniels, LLP John Marcil Partner Boulder, CO	Full service law firm providing business solutions
e)	Regulated Capital Consultants Jonathan D. Williams President Atlanta, GA	Business process and software solutions in accounting, tax, and regulatory matters
f)	Shapiro Lifschitz & Schram, P.C. Judah Lifschitz Co-President Washington, DC	Boutique law firm focusing on construction, real estate, and energy
g)	SunEdison Faisal El Azzouzi Director, Advanced Energy Solutions Belmont, CA	Development, financing, and operation of solar energy solutions

h)	Tata Consultancy Services Supratik Chaudhuri Marketing Manager Edison, NJ	Management, business solutions and IT consulting
i)	ViaSat, Inc. Brett Luedde Director, Critical Infrastructure Protection Carlsbad, CA	Innovative and secure satellite and digital communications

These additions are offset by several Associate Members that have dropped their EEI membership for various reasons: Cooper Power Systems; G-Cube Insurance Services; Grid Net; Laurel Hill Advisory Group; Petra Solar; and Q-Cells North America.

With these changes, EEI will have 263 Associates.

Report to the Edison Electric Institute Board of Directors

EEI PowerPAC

September 2013
Colorado Springs, CO

Table of Contents

Paid for by **PowerPAC** of the **Edison Electric Institute**.

Contributions to POWER PAC cannot be deducted as a charitable contribution for federal tax purposes. Federal law requires us to use our best efforts to collect and report the name, mailing address, occupation and the name of the employer of individuals whose contributions exceed $200 per calendar year. Contributions to POWER PAC are for political purposes only. Contributions are voluntary and you have a right to refuse to contribute without reprisal. The above guidelines are merely suggestions. You are free to contribute more or less than the suggested amount. You will not be favored or disadvantaged by reason of the amount you contribute or your decision not to contribute.

Treasurer's Report

EEI PowerPAC

Treasurer's Report

June 2013 Treasurer's Report

2014 Election Cycle: 1/01/2013 – 08/20/2013

Receipts	
PAC to PAC Contributions	$122,500.00
CEO and Member Company Executive Contributions	$174,550.00
Washington Representatives	$22,150.00
EEI Employee Contributions	$44,298.22
Total Election Cycle Receipts	$363,498.22

Disbursements	
Contributions to Candidates	$154,500.00
Other Contributions	$136,000.00

Summary	
Receipts	$363,498.22
Cash on Hand Year End 2012	$19,463.87
Disbursements	$290,500.00

August 20, 2013 Cash on Hand	$92,462.09

Steering Committee

EEI PowerPAC

EEI PowerPAC

2013 PowerPAC Steering Committee

Jessica Hogle
PG&E Corporation
Chairman

Robbie Aiken
Pinnacle West Capital Corporation

David Arthur
PPL Corporation

Alicia Cannon
American Electric Power

Kelly Chapman
Dominion

Maurie Dugger
Treasurer, PowerPAC

EmilyFisher
Edison Electric Institute

Fritz Hirst
TECO Energy Inc.

Shaun Garrison
Ameren Services

Chris Hickling
Edison Electric Institute

Kristen Ludecke
Public Service Enterprise Group Inc.

David Markarian
NextEra Energy Inc.

Chris Mathey
Exelon Corporation

Mike Poling
Great Plains Energy Inc.

Ann Pride
Entergy Corporation

Mike Sewell
Duke Energy

2013 Individual Contributions

EEI PowerPAC

2013 Individual Contributions

The following individuals have contributed up to $5,000 to PowerPAC since January 1, 2013

Name	Company
Greg Abel	MidAmerican Energy Holdings Co.
Nick Akins	American Electric Power
Tony Alexander	FirstEnergy Corporation
Gerry Anderson	DTE Energy
Don Brandt	Pinnacle West Capital Corporation
David Christian	Dominion
Pat Vincent-Collawn	PNM Resources
Chris Crane	Exelon Corporation
Ted Craver	Edison International
Tony Earley, Jr.	PG&E Corporation
Tom Fanning	Southern Company
Tom Farrell	Dominion
Ben Fowke	Xcel Energy
Lew Hay, III	NextEra Energy Inc.
Tom King	National Grid
Paul Koonce	Dominion Virginia Power
Tom Kuhn	Edison Electric Institute
David McClanahan	CenterPoint Energy Inc.
David Owens	Edison Electric Institute
Jim Robo	NextEra Energy Inc.
Jim Rogers	Duke Energy
Quin Shea	Edison Electric Institute
Bill Spence	PPL Corporation
Thomas Voss	Ameren Corporation
Brian Wolff	Edison Electric Institute
Michael Yackira	NV Energy
John Young	Energy Future Holdings

2013 Individual Contributions

The following participants have contributed or made a commitment of at least $2,000 to PowerPAC since January 1, 2013

Name	Company
Scott Aaronson	Edison Electric Institute
David Brown	Exelon Corporation
Kevin Burke	Consolidated Edison Inc.
Dan Cole	Ameren Services
Ed Comer	Edison Electric Institute
Peter Delaney	OGE Energy Corporation
Maurie Dugger	Edison Electric Institute
John Easton	Edison Electric Institute
Al Hodnik	ALLETE
Ralph Izzo	Public Service Enterprise Group Inc.
Chris Johns	PG&E Corporation
Patricia Kampling	Alliant Energy Corporation
Steven Lant	CH Energy Group
Brian McCormack	Edison Electric Institute
Ed McIntyre	Otter Tail Corporation
Richard McMahon	Edison Electric Institute
Mary Miller	Edison Electric Institute
Scott Morris	Avista Corporation
Mark Planning	Edison Electric Institute
Ann Pride	Entergy Corporation
John Ramil	TECO Energy Inc.
Joe Rigby	Pepco Holdings Inc.
Mark Ruelle	Westar Energy
John Schlenker	Edison Electric Institute
Bob Schoenberger	Unitil Corporation
Charlie Schrock	Integrys Energy Group
Tom Shockley	El Paso Electric
Kathy Steckelberg	Edison Electric Institute
Rick Tempchin	Edison Electric Institute
Bill Von Hoene	Exelon Corporation

2013 Individual Contributions

The following participants have contributed or made a commitment of at least $1,000 to PowerPAC since January 1, 2013

Name	Company
George Baker	Williams & Jensen
Terry Bassham	Great Plains Energy Inc.
Brad Beecher	Empire District Electric Company
David Bridges	Edison Electric Institute
Dan Chartier	Edison Electric Institute
Darnell DeMasters	Wisconsin Energy Corporation
Jim Fama	Edison Electric Institute
David Gilbert	Exelon Corporation
Eric Grey	Edison Electric Institute
Robert Grey	PPL Corporation
Mat Hastings	Edison Electric Institute
Chris Hickling	Edison Electric Institute
Barbara Hindin	Edison Electric Institute
Jessica Hogle	PG&E Corporation
Eric Holdsworth	Edison Electric Institute
Tony Ingram	Edison Electric Institute
Lou Jahn	Edison Electric Institute
Paul Kaleta	NV Energy
Connie Lau	Hawaiian Electric Industries Inc.
Melissa Lavinson	PG&E Corporation
Ron Litzinger	Southern California Edison Company
David Markarian	NextEra Energy Inc.
Cal Odom	Edison Electric Institute
Jim Owen	Edison Electric Institute
Dilek Samil	NV Energy
Tony Sanchez	NV Energy
Jim Torgerson	UIL Holdings Corporation
Dan Turton	Entergy Corporation

2013 Individual Contributions

The following participants have given personal contributions up to $1,000 to PowerPAC since January 1, 2013

Name	Company
Anthony Alexander, Jr.	FirstEnergy
David Arthur	PPL Corporation
David Baker	CenterPoint Energy Inc.
Carolyn Barbash	NV Energy
Bob Bartlett	Alliant Energy Corporation
Ann Becker	Arizona Public Service Company
Cindy Berger	Arizona Public Service Company
Kevin Bethel	NV Energy
Ray Billups	Consultant
Todd Black	Unitil Corporation
Dale Bodden	CenterPoint Energy Inc.
Cari Boyce	Duke Energy
Tracy Bridge	CenterPoint Energy Inc.
Karen Britto	DTE Energy
Bruce Bullock	NV Energy
Stoney Burke	Southern Company
Mike Carano	NV Energy
Jackie Carney	Exelon Corporation
David Carpenter	El Paso Electric
Rick Carter	National Grid
Kelly Chapman	Dominion
Caroline Choi	Southern California Edison Company
Alice Cobb	NV Energy
Mark Collin	Unitil Corporation
Kiran Crout	CMS Energy Corporation
Denise Danner	Arizona Public Service Company
David DeCampli	PPL Corporation
Roberto Denis	NV Energy
Pat Dinkel	Arizona Public Service Company
Greg Dudkin	PPL Corporation
Mike Eckard	FirstEnergy

2013 Individual Contributions

The following participants have given personal contributions up to $1,000 to PowerPAC since January 1, 2013, Continued

Name	Company
David Falck	Pinnacle West Capital Corporation
Ed Fox	Arizona Public Service Company
Daniel Froetscher	Arizona Public Service Company
Shaun Garrison	Ameren Services
Kevin Geraghty	NV Energy
Barb Gomez	Arizona Public Service Company
Frank Gonzales	NV Energy
Allison Graves	Entergy Corporation
Jeffrey Guldner	Arizona Public Service Company
David Hansen	Arizona Public Service Company
John Hatfield	Arizona Public Service Company
Jim Hatfield	Pinnacle West Capital Corporation
Fritz Hirst	TECO Energy Inc.
Kevin Judice	NV Energy
Anthony Kavanagh	American Electric Power
John Kellum	CenterPoint Energy Inc.
Greg Kern	NV Energy
Mary Kipp	El Paso Electric
Starla Lacy	NV Energy
Norm Lent	DowLohnes Government Strategies
Bill Libro	ALLETE
Paul Lobo	Policy Integration Partners, LLC
Ann Loomis	Dominion
Chris Mathey	Exelon Corporation
Bruce McKay	Dominion
Tammy McLeod	Arizona Public Service Company
Andy McNeill	NV Energy
Tom Meissner	Unitil Corporation
Kenny Mercado	CenterPoint Energy Inc.
Rocky Miracle	El Paso Electric
Nancy Moody	DTE Energy

2013 Individual Contributions

The following participants have given personal contributions up to $1,000 to PowerPAC since January 1, 2013, Continued

Name	Company
Lee Nickloy	Pinnacle West Capital Corporation
Matthew Nugen	Integrys Energy Group Inc.
Jeanette Pablo	Navitas Strategies
Nelson Perez	National Grid
Mike Poling	Great Plains Energy Inc.
Amy Pressler	Edison International
Scott Prochazka	CenterPoint Energy Inc.
Hector Puente	El Paso Electric
John Rainbolt	Alliant Energy Corporation
Kevin Reckeloff	CenterPoint Energy Inc.
Dariusz Rekowski	NV Energy
Bob Rowe	NorthWestern Energy
Conrad Schatte	Entergy Corporation
Mark Schiavoni	Arizona Public Service Company
Mike Sewell	Duke Energy
Mark Shank	NV Energy
Toby Short	Duke Energy
Mary Simmons	NV Energy
John Slanina	CenterPoint Energy Inc.
Mary Sprayregen	Consolidated Edison Inc.
Robert Stewart	NV Energy
Rob Stillwell	NV Energy
Judy Stokey	NV Energy
Lori Sundberg	Arizona Public Service Company
Mario Villar	NV Energy

2013 Individual Contributions

The following EEI employees have given personal contributions or commitments to PowerPAC since January 1, 2013

Name	Name
Scott Aaronson	John Kinsman
Eric Ackerman	Tom Kuhn
Mark Agnew	Rick Loughery
Sarah Ball	Brian McCormack
Taylor Beis	Jennifer McKinney
Karen Bernard	Richard McMahon
Rich Bozek	Wally Mealiea
David Bridges	Mary Miller
Bruce Brown	Jon Myers
Dan Chartier	Gayle Novak
Ed Comer	Cal Odom
Adam Cooper	Richard O'Grady
Maurie Dugger	Terri Oliva
John Easton	Jim Owen
Chris Eisenbrey	David Owens
Jim Fama	Mark Planning
Emily Fisher	Jim Roewer
Eric Grey	John Schlenker
Miranda Gregory	Quin Shea
Becky Harsh	Louise Smoak
Mat Hastings	Kathy Steckelberg
Chris Hickling	Liz Stipnieks
Barbara Hindin	Rick Tempchin
Jeanny Ho	Brad Viator
Eric Holdsworth	Stephanie Voyda
Meg Hunt	Richard Ward
Tony Ingram	Karla Whiting
Lou Jahn	Brian Wolff
Charles Kelly	Lisa Wood
Steve Kiesner	

2013 PAC to PAC Contributions

EEI PowerPAC

PAC-to-PowerPAC Contributor List

PAC-to-PAC contributions received since January 1, 2013

PAC	Contribution
ALLETE PAC	$1,000.00
Alliant Energy PAC	$1,000.00
Ameren Federal PAC	$5,000.00
AEP Committee for Responsible Government	$5,000.00
CenterPoint Energy PAC	$2,500.00
CMS Energy Employees for Better Government	$5,000.00
Dominion PAC	$5,000.00
DTE Energy PAC	$5,000.00
Duke Energy PAC	$5,000.00
Edison International PAC	$5,000.00
Energy Future Holdings PAC	$5,000.00
ENPAC - Entergy Corporation	$5,000.00
Exelon PAC	$5,000.00
FirstEnergy PAC	$5,000.00
KCPL PowerPAC	$2,000.00
MDU Resources PAC	$2,000.00
National Grid GridPAC	$4,000.00
NextEra Energy PAC	$5,000.00
NiSource Inc. PAC	$2,000.00
NV Energy PAC	$5,000.00
OGE Energy Corp. Employee's PAC	$5,000.00
Pepco Holdings Inc. PAC	$5,000.00
PG&E Corporation Energy PAC	$5,000.00
Pinnacle West PAC	$5,000.00
PNM Resources PAC	$5,000.00
PPL People for Good Government PAC	$5,000.00
Public Service Enterprise Group PAC	$1,500.00
Southern Company PAC	$5,000.00
TECO Energy Employee's PAC	$3,000.00
Vectren Corporation Employees Federal PAC	$2,500.00
Wisconsin Energy’s WE PAC	$1,000.00

2013 Disbursements

EEI PowerPAC

2013-2014 Disbursements

State	Candidate Name	Committee	Party	Type	Amount
Alabama					
	Senator Jeff Sessions	Friends of Sessions for Senate	Republican	Candidate	$2,500.00
	Senator Richard Shelby	Defend America PAC	Republican	Leadership	$2,000.00
Alaska					
	Senator Lisa Murkowski	Lisa Murkowski for US Senate	Republican	Candidate	$2,500.00
	Senator Lisa Murkowski	Denali Leadership PAC	Republican	Leadership	$5,000.00
	Senator Mark Begich	Great Land PAC	Democrat	Leadership	$2,500.00
Arizona					
	Congressman Matt Salmon	Salmon for Congress	Republican	Candidate	$1,000.00
Arkansas					
	Senator Mark Pryor	Mark Pryor for US Senate	Democrat	Candidate	$2,000.00
California					
	Congressman Jeff Denham	Denham for Congress	Republican	Candidate	$1,000.00
	Congressman Doris Matsui	Matsui for Congress	Democrat	Candidate	$2,000.00
	Congressman Kevin McCarthy	Kevin McCarthy for Congress	Republican	Candidate	$2,500.00
	Congressman Devin Nunes	New PAC	Republican	Leadership	$2,500.00
	Congressman Mike Thompson	Mike Thompson for Congress	Democrat	Candidate	$2,500.00
	Congressman David Valadao	Valadao for Congress	Republican	Candidate	$1,000.00
Colorado					
	Senator Mark Udall	Udall For Colorado	Democrat	Candidate	$1,500.00
Delaware					
	Senator Chris Coons	Chris Coons for Delaware	Democrat	Candidate	$2,500.00
Florida					
	Senator Marco Rubio	Reclaim America PAC	Republican	Leadership	$2,500.00
	Congressman John Mica	Mica for Congress	Republican	Candidate	$1,000.00
Georgia					
	Congressman John Barrow	Friends of John Barrow	Democrat	Candidate	$5,000.00
Idaho					
	Congressman Michael Simpson	Simpson for Congress	Republican	Candidate	$2,000.00

2013-2014 Disbursements

Illinois					
	Congressman Adam Kinzinger	Kinzinger for Congress	Republican	Candidate	$2,000.00
	Congressman Peter Roskam	Roskam for Congress	Republican	Candidate	$2,500.00
	Congressman Peter Roskam	ROSKAM PAC	Republican	Leadership	$3,000.00
	Congressman Bobby Rush	Citizens for Rush	Democrat	Candidate	$2,000.00
	Congressman Aaron Schock	Schock for Congress	Republican	Candidate	$2,000.00
	Congressman John Shimkus	Volunteers for Shimkus	Republican	Candidate	$2,000.00
Indiana					
	Congressman Pete Visclosky	Visclosky for Congress	Democrat	Candidate	$2,500.00
Kansas					
	Congresswoman Lynn Jenkins	Lynn Jenkins for Congress	Republican	Candidate	$2,000.00
Kentucky					
	Senator Mitch McConnell	McConnell Senate Committee 2014	Republican	Candidate	$5,000.00
	Congressman Ed Whitfield	Whitfield for Congress	Republican	Candidate	$5,000.00
Louisiana					
	Senator Mary Landrieu	Friends of Mary Landrieu	Democrat	Candidate	$2,000.00
	Senator David Vitter	David Vitter for US Senate	Republican	Candidate	$1,500.00
	Congressman Cedric Richmond	Richmond for Congress	Democrat	Candidate	$1,000.00
	Congressman Steve Scalise	Scalise for Congress	Republican	Candidate	$2,000.00
	Congressman Steve Scalise	Eye of the Tiger	Republican	Leadership	$2,500.00
Maryland					
	Congressman Steny H. Hoyer	Hoyer For Congress	Democrat	Candidate	$5,000.00
	Congressman Steny H. Hoyer	AMERIPAC	Democrat	Leadership	$5,000.00
Michigan					
	Congressman Dan Benishek	Benishek for Congress	Republican	Candidate	$1,000.00
	Congressman Dave Camp	Dave Camp for Congress	Republican	Candidate	$2,500.00
	Congressman Dave Camp	CAMP PAC	Republican	Leadership	$5,000.00
	Congressman John D. Dingell	John D. Dingell for Congress	Democrat	Candidate	$2,000.00
	Congressman Mike Rogers	Mike Rogers for Congress	Republican	Candidate	$5,000.00
	Congressman Fred Upton	Upton for All of Us	Republican	Candidate	$5,000.00
	Congressman Fred Upton	TRUST PAC	Republican	Leadership	$5,000.00

2013-2014 Disbursements

Missouri					
	Congresswoman Ann Wagner	Ann Wagner for Congress	Republican	Candidate	$1,000.00
Mississippi					
	Congressman Gregg Harper	Gregg Harper for Congress	Republican	Candidate	$1,000.00
Montana					
	Senator Max Baucus	Friends of Max Baucus	Democrat	Candidate	$2,500.00
	Senator Max Baucus	Glacier Pac	Democrat	Leadership	$5,000.00
Nebraska					
	Congressman Lee Terry	Lee Terry for Congress	Republican	Candidate	$2,000.00
New Jersey					
	Congressman Rodney Frelinghuysen	Frelinghuysen for Congress	Republican	Candidate	$2,500.00
New York					
	Senator Chuck Schumer	Friends of Schumer	Democrat	Candidate	$2,000.00
	Congressman Joseph Crowley	Crowley for Congress	Democrat	Candidate	$2,000.00
	Congressman Tom Reed	Tom Reed for Congress	Republican	Candidate	$2,000.00
	Congressman Paul Tonko	Paul Tonko for Congress	Democrat	Candidate	$2,000.00
North Carolina					
	Congressman Mike McIntyre	Mike McIntyre for Congress	Democrat	Candidate	$1,000.00
Ohio					
	Speaker John Boehner	Friends of John Boehner	Republican	Candidate	$5,000.00
	Speaker John Boehner	The Freedom Project	Republican	Leadership	$5,000.00
	Congressman Bill Johnson	Johnson for Congress	Republican	Candidate	$2,000.00
	Congresswoman Marcy Kaptur	Kaptur for Congress	Democrat	Candidate	$1,000.00
Oklahoma					
	Senator Jim Inhofe	Fund for A Conservative Future	Republican	Leadership	$1,000.00
Oregon					
	Senator Ron Wyden	Wyden for Senate	Democrat	Candidate	$5,000.00
	Congressman Greg Walden	Walden for Congress	Republican	Candidate	$5,000.00
Pennsylvania					
	Congressman Charlie Dent	Dent for Congress	Republican	Candidate	$2,000.00
	Congressman Joe Pitts	Friends of Joe Pitts	Republican	Candidate	$1,000.00
	Congressman Tim Murphy	Tim Murphy for Congress	Republican	Candidate	$2,000.00

2013-2014 Disbursements

South Carolina					
	Senator Tim Scott	Tim Scott for Senate	Republican	Candidate	$2,500.00
	Congressman Jim Clyburn	Friends of Jim Clyburn	Democrat	Candidate	$5,000.00
	Congressman Jim Clyburn	BRIDGE PAC	Democrat	Leadership	$5,000.00
Tennessee					
	Senator Lamar Alexander	Alexander for Senate	Republican	Candidate	$2,500.00
Texas					
	Congressman Joe Barton	Congressman Joe Barton Committee	Republican	Candidate	$5,000.00
	Congressman Michael Burgess	Michael Burgess for Congress	Republican	Candidate	$2,000.00
	Congressman Ralph Hall	Hall for Congress Committee	Republican	Candidate	$1,000.00
	Congressman Jeb Hensarling	Friends of Jeb Hensarling	Republican	Candidate	$1,000.00
	Congressman Pete Olson	Olson for Congress Committee	Republican	Candidate	$1,000.00
	Congressman Pete Sessions	Pete Sessions for Congress	Republican	Candidate	$2,000.00
Utah					
	Congressman Jim Matheson	Matheson for Congress	Democrat	Candidate	$1,500.00
Vermont					
	Congressman Peter Welch	Welch for Congress	Democrat	Candidate	$1,000.00
Virginia					
	Congressman Eric Cantor	ERIC PAC	Republican	Leadership	$5,000.00
West Virginia					
	Congressman David McKinley	McKinley for Congress	Republican	Candidate	$2,000.00
	Congressman Shelley Capito	Capito for West Virginia	Republican	Candidate	$2,500.00
Wisconsin					
	Congressman Paul Ryan	Ryan for Congress, Inc.	Republican	Candidate	$2,500.00
	Congressman Mark Pocan	Mark Pocan for Congress	Democrat	Candidate	$1,000.00
Caucuses					
	Blue Dog Coalition	Blue Dog PAC	Democrat	Caucus PAC	$5,000.00
	NewDem Coalition	NewDem PAC	Democrat	Caucus PAC	$5,000.00
	Republican Mainstreet Partnership	Republican Mainstreet Partnership PAC	Republican	Caucus PAC	$5,000.00
	Moderate Senate Democrats	Moderate Democrats PAC	Democrat	Caucus PAC	$5,000.00

2013-2014 Disbursements

Committees				
	Democratic Congressional Campaign Committee	Democrat	Party	$15,000.00
	Democratic Senatorial Campaign Committee	Democrat	Party	$15,000.00
	National Republican Congressional Committee	Republican	Party	$15,000.00
	National Republican Senatorial Committee	Republican	Party	$15,000.00
			TOTAL	$290,500.00

Paid for by **PowerPAC** of the **Edison Electric Institute**.

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EEI PowerPAC

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Resolution Supporting the Troops to Energy Jobs Initiative

WHEREAS, The Troops to Energy Jobs Initiative is an effort by the energy industry to develop an accelerated process for bringing returning military veterans into the energy industry workforce nationwide;

WHEREAS, Many veterans already possess the skills, knowledge and discipline required for energy careers, particularly for engineering, technician, lineworker and plant operator positions;

WHEREAS, The Troops to Energy Jobs Initiative opens a needed and natural employment pipeline between the military and our country's energy industries;

WHEREAS, The Troops to Energy Jobs Initiative has been developed through a joint effort of six energy companies: Dominion, American Electric Power, National Grid, Pacific Gas and Electric Company, Pinnacle West Capital Corporation/Arizona Public Service and Southern Company, and seeks to expand the program to the entire energy industry;

WHEREAS, The six pilot companies, working with the Center for Energy Workforce Development created a National Template as a blueprint for utilities who wish to Plan, Build, Implement and Measure initiatives that will:

- Make it easier for veterans to find energy jobs and to translate their skills and training
- Accelerate the time it takes veterans to earn required credentials or degrees
- Provide full value for military training and experience when hiring
- Create a military-friendly environment within the company
- Increase the number of veterans who are recruited, hired and retained in energy jobs;

NOW THEREFORE BE IT RESOLVED, That the Edison Electric Institute Board of Directors supports the recommendations of the Troops to Energy Jobs Initiative;

BE IT FURTHER RESOLVED, That utilities, as well as community colleges and labor unions work together in support of this partnership between the U.S. military and the energy industry.

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Thomas F. Farrell, II

August 2013

EEI

CEO MEETING SCHEDULE

2013	September 10-12	Board & Chief Executive Meetings: The Broadmoor, Colorado Springs, CO
	November 10-13	Financial Conference: Orlando World Marriott Resort, Orlando, FL
2014	January 7-9	Board & Chief Executive Meetings: Arizona Biltmore, Phoenix, AZ
	March 4-6	Board & Chief Executive Meetings: Mandarin Oriental, Washington, DC
	June 8-11	Annual Convention & Board Mtg.: ARIA Resort & Casino, Las Vegas, NV
	September 2-4	Board & Chief Executive Meetings: The Broadmoor, Colorado Springs, CO
2015	January 6-8	Board & Chief Executive Meetings: The Breakers, Palm Beach, FL
	March 17-19	Board & Chief Executive Meetings: Mandarin Oriental, Washington, DC
	June 7-10	Annual Convention & Board Mtg.: Hyatt Regency, New Orleans, LA
	September 8-10	Board & Chief Executive Meetings: The Broadmoor, Colorado Springs, CO
2016	January 5-7	Board & Chief Executive Meetings: The Fairmont Scottsdale Princess, Scottsdale, AZ
	September 6-8	Board & Chief Executive Meetings: The Broadmoor, Colorado Springs, CO
	June 19-22	Annual Convention & Board Mtg.: Manchester Grand Hyatt, San Diego, CA
2017	September 5-7	Board & Chief Executive Meetings: The Broadmoor, Colorado Springs, CO